NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

December 21, 2011

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: *North American Electric Reliability Corporation*
Docket No._______

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits this petition in accordance with Section 215(d)(1) of the Federal Power Act ("FPA") and Part 39.5 of the Federal Energy Regulatory Commission's ("FERC" or the "Commission") regulations seeking:

- approval of Reliability Standard FAC-003-2 — Transmission Vegetation Management (FAC-003-2) and the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs"), included in **Exhibit A** to the petition, effective the first day of the first calendar quarter one year following the effective date of a Final Rule in this docket;[1]

- approval of three proposed definitions to be added to the NERC Glossary of Terms used in the NERC Reliability Standards effective the first day of the first calendar quarter one year following the effective date of a Final Rule in this docket:

  - Right-of-Way
  - Vegetation Inspection
  - Minimum Vegetation Clearance Distance ("MVCD")

[1] Because the proposed FAC-003-2 standard has been substantially revised, a redlined version of FAC-003-2 is not included in this filing, as it would be difficult to read and of limited value.

- approval of the implementation plan for Reliability Standard FAC-003-2 — Transmission Vegetation Management which is included in **Exhibit B** to the petition; and

- approval of the retirement of Reliability Standard FAC-003-1 — Transmission Vegetation Management Program (FAC-003-1) and the currently effective NERC Definitions for "Right-of-Way" and "Vegetation Inspection" effective midnight immediately prior to the first day of the first calendar quarter that is a year following the effective date of a Final Rule in this docket:

The proposed FAC-003-2 standard addresses the important goal of managing vegetation to maintain a reliable electric transmission system and presents three themes that all help to improve reliability. First, reliability will be improved with implementation of the new standard. Second, enforceability of FAC-003-2, as compared to FAC-003-1, will be improved and cleaner for NERC and the Regional Entities. And third, NERC registered entities will have greater flexibility to address local vegetation management conditions.

Ineffective vegetation management was identified as a major cause of the August 14, 2003, blackout, and has also been a causal factor in other large-scale North American outages such as those that occurred in the summer of 1996 in the western United States.[2] Recommendation 16 of the Blackout Report[3] suggests the establishment of enforceable standards for maintenance of electrical clearances in right-of-way areas. NERC "raised the bar" with the development of the FAC-003-1 Reliability Standard, and the

[2] *See, Final Report on the August 14, 2003 Blackout in the United States and Canada: causes and Recommendations,* U.S.-Canada Power System Outage Task Force, April 5, 2004, at p. 154 ("Blackout Report").
[3] Blackout Report, Recommendation 16.

enhancements to the standard included with this filing represents another "raising of the bar." Unlike the previous standard, which is primarily focused on the "Transmission Vegetation Management Program," the new version of FAC-003 has a broader focus on "Transmission Vegetation Management," which is reflected both in the title of the standard and the fact that there are now results-based performance requirements that require specific actions, rather than just documentation.

The general improvements compared to the previous version of the standard are shown in the table below:

Requirement in Existing FAC-003-1 Standard	Improvements in Proposed FAC-003-2 Standard
Requires a document that includes vegetation management objectives, approved procedures, and work specifications. (R1)	Requires documented vegetation management maintenance strategies, procedures, processes, or specifications that will prevent encroachment into the Minimum Vegetation Clearance Distance (MVCD) (R3)
Requires a document schedule for ROW vegetation inspections. (R1.1)	Requires vegetation inspection of 100% of applicable transmission lines at least once per calendar year. (R6)
Requires documentation of a "Clearance 1" value based on TO assessment of situation and risk. (R1.2 and R1.2.1)	Requires vegetation be managed such that no encroachments into the MVCD (as established by the Gallet Equation) occur, regardless of whether or not they result in a sustained outage. (R3, parts 3.1 and 3.2)
Requires documentation of a "Clearance 2" value based on IEEE standard. (R1.2.2, R1.2.2.1, and R1.2.2.2)	Requires vegetation be managed such that no encroachments into the MVCD (as established by the Gallet Equation) occur, regardless of whether or not they result in a sustained outage. (R1 and R2)
Requires documentation of mitigation	Requires corrective action to be taken in cases

measures to address locations on the on the ROW where the TO is restricted from attaining specified clearances. (R1.4)	where a TO is constrained from performing vegetation work. (R5)
Requires documentation of a process for communicating imminent threats where vegetation conditions could lead to a transmission line outage. (R1.5)	Requires TOs, without any intentional time delay, to notify the control center holding switching authority for the associated applicable line when the TO has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment. (R4)
Requires the creation and implementation of an annual vegetation management plan, as well as a process for documenting and tracking the execution of the plan. (R2)	Requires the TOs annual vegetation management plan be executed such that no vegetation encroachments occur within the MVCD. (R7)

Accordingly, the proposed FAC-003-2 standard should be approved because it serves the important reliability goal of providing clear, unambiguous standards pertaining to maintenance of safe clearances of transmission lines from obstructions in the lines' right-of-way areas – in this case, specifically with regard to vegetation management.

The proposed FAC-003-2 standard was approved by the NERC Board of Trustees on November 3, 2011.

This petition consists of the following:

- This transmittal letter;
- A table of contents for the entire petition;
- A narrative description explaining how the proposed Reliability Standard FAC-003-2 — Transmission Vegetation Management meets FERC's requirements;
- Reliability Standard FAC-003-2 — Transmission Vegetation Management submitted for approval (**Exhibit A**);
- Implementation Plan for Reliability Standard FAC-003-2 — Transmission Vegetation Management submitted for Approval (**Exhibit B**);

- Proposed Definitions to be Added to the NERC Glossary of Terms Used in NERC Reliability Standards (**Exhibit C**)
- FAC-003-1 Mapping to Proposed NERC Reliability Standard FAC-003-2 summarizing the transition of requirements and related information from FAC-003-1 to FAC-003-2 ("Mapping Document") (**Exhibit D**)
- Consideration of Comments Reports created during the development of Reliability Standard FAC-003-2 — Transmission Vegetation Management (**Exhibit E**);
- Analysis of how VRFs and VSLs Were Determined Using FERC Guidelines (**Exhibit F**);
- The complete development record of the proposed Reliability Standard (**Exhibit G**);
- The Standard Drafting Team Roster for NERC Standards Development Project 2007-07 Vegetation Management (**Exhibit H**); and
- Transmission Vegetation Management – FAC-003-2 Technical Reference Document (**Exhibit I**).

For the reasons stated above and in this petition, NERC respectfully requests that the Commission approve the standard presented herein for approval.

Respectfully submitted,

/s/ Holly A. Hawkins
Holly A. Hawkins
Assistant General Counsel for North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**) Docket No. RM-__-000** **)**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARD FAC-003-2 — TRANSMISSION VEGETATION MANAGEMENT

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I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC")[4] hereby requests the Federal Energy Regulatory Commission ("FERC") to approve, in accordance with Section 215(d)(1) of the Federal Power Act ("FPA")[5] and Section 39.5 of FERC's regulations, 18 C.F.R. § 39.5, the proposed FAC-003-2 — Transmission Vegetation Management Reliability Standard approved by the NERC Board of Trustees on November 3, 2011. The proposed FAC-003-2 Reliability Standard improves reliability by maintaining a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way ("ROW") and by minimizing encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading. Additionally, the FAC-003-2 standard helps to enhance reliability by improving enforceability of FAC-003-2, as compared to FAC-003-1, and by providing greater flexibility to NERC registered entities to address local vegetation management conditions.

By this petition, NERC is requesting approval of the proposed FAC-003-2 Reliability Standard, three proposed NERC Glossary Definitions, Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs"), the corresponding implementation plan, and retirement of one currently-effective Reliability Standard. Specifically, NERC requests approval of the following:

- approval of Reliability Standard FAC-003-2 — Transmission Vegetation Management and the associated Violation Risk Factors and Violation Severity Levels (FAC-003-2), which is included in **Exhibit A,** effective the first day of

[4] NERC has been certified by FERC as the electric reliability organization ("ERO") in accordance with Section 215 of the Federal Power Act. FERC certified NERC as the ERO in its order issued July 20, 2006 in Docket No. RR06-1-000. 116 FERC ¶ 61,062 (2006) ("ERO Certification Order).
[5] 16 U.S.C. 824o (2011).

the first calendar quarter that is twelve months following the effective date of a Final Rule in this docket;[6]

- approval of the implementation plan for Reliability Standard FAC-003-2 — Transmission Vegetation Management which is included in **Exhibit B**;

- approval of three proposed Definitions included in **Exhibit C** to be added to the NERC Glossary of Terms Used in NERC Reliability Standards effective the first day of the first calendar quarter that is twelve months following the effective date of a Final Rule in this docket:

  - **Right-of-Way (ROW)** – The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.

  - **Vegetation Inspection** - The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

  - **Minimum Vegetation Clearance Distance (MVCD)** - The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

- approval of the retirement of Reliability Standard FAC-003-1 — Transmission Vegetation Management Program (FAC-003-1) and the currently effective definitions of "Right-of-Way" and "Vegetation Inspection" effective midnight immediately prior to the first day of the first calendar quarter that is twelve months following the effective date of a Final Rule in this docket.

The NERC Board of Trustees approved the proposed FAC-003-2 Reliability Standard on November 3, 2011. **Exhibit A** to this petition sets forth FAC-003-2 submitted for approval. **Exhibit B** contains the Implementation Plan for FAC-003-2 submitted for Approval. **Exhibit C** contains three proposed glossary terms proposed for

[6] Because the proposed FAC-003-2 standard has been substantially revised, a redlined version of FAC-003-2 is not included in this filing.

approval to be added to the NERC Glossary of Terms Used in NERC Reliability Standards. **Exhibit D** contains the FAC-003-1 Mapping to Proposed NERC Reliability Standard FAC-003-2 document ("Mapping Document") summarizing the transition of requirements and related information from FAC-003-1 to FAC-003-2. **Exhibit E** contains the Consideration of Comments Reports created during the development of the FAC-003-2 standard. **Exhibit F** contains an analysis of how VRFs and VSLs were determined using FERC Guidelines. **Exhibit G** contains the complete record of development for FAC-003-2. **Exhibit H** includes the roster and biographies for the standard drafting team appointed by the NERC Standards Committee to Project 2007-07 - Transmission Vegetation Management, the standard drafting team responsible for developing FAC-003-2. **Exhibit I** includes the Transmission Vegetation Management – FAC-003-2 Technical Reference Document (Appendix 1 to that document discusses the Gallet Equation).

II. EXECUTIVE SUMMARY

The proposed FAC-003-2 Reliability Standard represents an improvement over the currently-effective FAC-003-1 standard because it more clearly defines a defense-in-depth strategy to manage vegetation located on transmission ROW to minimize encroachments from vegetation located adjacent to the ROW, thus reducing the risk of those vegetation-related outages that could lead to Cascading. The proposed FAC-003-2 Reliability Standard presents three themes that all help to improve reliability. First, reliability will be improved with implementation of the new standard. Second, enforceability of FAC-003-2, as compared to FAC-003-1, will be improved and cleaner for NERC and the Regional Entities. And third, NERC registered entities will have greater flexibility to address local vegetation management conditions.

The general improvements compared to the previous version of the standard are shown in the table below:

Requirement in Existing FAC-003-1 Standard	**Improvements in Proposed FAC-003-2 Standard**
Requires a document that includes vegetation management objectives, approved procedures, and work specifications. (R1)	Requires documented vegetation management maintenance strategies, procedures, processes, or specifications that will prevent encroachment into the Minimum Vegetation Clearance Distance (MVCD) (R3)
Requires a document schedule for ROW vegetation inspections. (R1.1)	Requires vegetation inspection of 100% of applicable transmission lines at least once per calendar year. (R6)
Requires documentation of a "Clearance 1" value based on TO assessment of situation and risk. (R1.2 and R1.2.1)	Requires vegetation be managed such that no encroachments into the MVCD (as established by the Gallet Equation) occur, regardless of whether or not they result in a sustained outage. (R3, parts 3.1 and 3.2)
Requires documentation of a "Clearance 2" value based on IEEE standard. (R1.2.2, R1.2.2.1, and R1.2.2.2)	Requires vegetation be managed such that no encroachments into the MVCD (as established by the Gallet Equation) occur, regardless of whether or not they result in a sustained outage. (R1 and R2)
Requires documentation of mitigation measures to address locations on the on the ROW where the TO is restricted from attaining specified clearances. (R1.4)	Requires corrective action to be taken in cases where a TO is constrained from performing vegetation work. (R5)
Requires documentation of a process for communicating imminent threats where vegetation conditions could lead to a transmission line outage. (R1.5)	Requires TOs, without any intentional time delay, to notify the control center holding switching authority for the associated applicable line when the TO has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment. (R4)
Requires the creation and implementation of an annual vegetation management plan, as well as a process for documenting and tracking the execution of the plan. (R2)	Requires the TOs annual vegetation management plan be executed such that no vegetation encroachments occur within the MVCD. (R7)

In Order No. 693, FERC identified shortcomings of the currently-effective FAC-003-1 standard, which have been addressed in this proposed version.[7] Additionally, FERC in its Order indicated the IEEE Standard 516-2003, upon which the previous standard was based, was "intended for use as a guide by highly-trained maintenance personnel to carry out live-line work using specialized tools under controlled environments and operating conditions, not for those conditions necessary to safely carry out vegetation management practices."[8] Further, the Commission stated "use of IEEE clearance provision as a basis for minimum clearance prior to the next tree trimming as a Requirement in vegetation management is not appropriate for safety and reliability reasons," and directed NERC to develop a Reliability Standard that defines the minimum clearance needed to avoid sustained vegetation-related outages.[9]

Because of the direction provided by FERC in Order No. 693 relative to the use of IEEE Standard 516-2003, the proposed FAC-003-2 Reliability Standard no longer utilizes the IEEE clearance provisions. The standard now requires minimum clearance distances derived from the Gallet Equation. There were four potential methods considered for use in the standard to derive flash-over distances for various voltages and altitudes. While each of the methods are expected to provide similar results,[10] the Gallet method was selected because Gallet method information to support the development of the standard was readily available in an industry recognized reference. This method

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[7] *Mandatory Reliability Standards for the Bulk-Power* System, Order No. 693, FERC Stats. & Regs. ¶ 31,242 (2007), *order on reh'*g Order No. 693-A, 120 FERC ¶ 61,053 (2007)("Order No. 693") at PP 731 and 732.
[8] *Id.*
[9] *Id.*
[10] EPRI, at its Lenox facility, is currently growing trees on a high voltage right-of-way test plot that will be ready for testing by the summer of 2013. These will be the first known field tests of energized high voltage conductor flash-over to vegetation. The results of those tests may be useful to the industry for future reviews of this NERC Standard.

allows clearance distance values for a given voltage to be derived for wet conditions at various altitudes. The distances derived using the Gallet Equation result in the probability of flashover in the range of 10^{-6}. This approach was used to design of some of the first 500 kV and 765 kV lines in North America.[11]

Additionally, this standard continues to provide the Transmission Owner with flexibility when determining the appropriate degree of vegetation removal. Similar to FAC-003-1, in which the Transmission Owner was given the authority to "determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner plans to return for future vegetation management work," FAC-003-2 provides the Transmission Owner the necessary discretion to determine how to manage vegetation. FAC-003-2 continues to allow Transmission Owners the ability to exercise their full legal rights without mandating any specific strategy or incorporating an arbitrary margin into the requirements of the standard absent specific knowledge of the actual conditions in the field.

Despite this flexibility, FAC-003-2 is actually more stringent than FAC-003-1. Essentially, with the new Requirements R1 and R2, FAC-003-2 presents a "zero-tolerance" approach to vegetation management, explicitly treating any encroachment into the MVCD (without contact, with a flashover, with a momentary outage, or with a sustained outage) as a violation of the standard. The standard also requires annual inspections (which go beyond what is required in FAC-003-1) and is much more explicit regarding what actions must be taken to support vegetation management and reliability.

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[11] Andrew Hileman, *Insulation Coordination for Power System*, Marcel Dekker, New York, NY 1999.

FAC-003-2 is also one of the first standards developed using NERC's new "results- based" approach and format. Each requirement meets one or more specific approaches (performance-based, risk-based, or competency-based) to achieving results, and the measures associated with each requirement have been developed to ensure that compliance with the standard can be verified. In addition to focusing on completing objectives, achieving goals, and meeting needs (three of the hallmarks of a results-based standard), FAC-003-2 identifies clear and objective measures for compliance, so that it can be enforced in a consistent and non-preferential manner. The standard also includes detailed background information and supporting documentation, making the requirements easier to comprehend and providing the rationale used by the drafting team for establishing the requirements.

As a results-based standard, there are some noticeable changes in the manner in which the requirements for the standard are structured. One of the most obvious is the replacement of Requirement R1 from FAC-003-1 with several new requirements in FAC-003-2. Requirement R1 from FAC-003-1 requires the Transmission Owner to have a formal Transmission Vegetation Management Plan ("TVMP") that includes several specific items. In FAC-003-2, the majority of the specific items have been extracted from the pages of the TVMP and made into explicit, actionable requirements. The requirement for the TVMP itself has been removed from the standard.

The TVMP required by FAC-003-1 was a good vehicle for ensuring that all key elements of vegetation management were considered as part of a Transmission Owner's overall vegetation management strategy. However, the drafting team that developed FAC-003-2 determined there were equally (or, in some cases more,) effective ways to ensure key vegetation management issues are addressed. Accordingly, the drafting team developed FAC-003-2 using results-based approaches that focused on what actions needed to be taken, as opposed to how documentation supporting vegetation management should be assembled. This resulted in a standard that ensures requirements are measureable and enforceable while providing significantly more flexibility than the previous standard. A detailed discussion of how the requirements in version one of the standard have been transitioned to version two of the standard is included below.

NERC believes FAC-003-2 will continue to provide the means by which the industry can demonstrate its commitment to reliability and vegetation management excellence. Moreover, by allowing more diverse approaches through the flexibility inherent in the new results-based requirements, FAC-003-2 correctly focuses on providing the industry the latitude it needs to meet the performance objectives important to reliability. The industry as a whole recognizes the importance of vegetation management. Like the previous version of the standard, FAC-003-2 is a channel through which the industry can measurably demonstrate that recognition. As such, NERC expects the current industry performance of vegetation management to continue or improve under FAC-003-2.

Additionally, there are more improvements that have been incorporated into proposed FAC-003-2 standard that are further detailed in the later sections of this petition.

III. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

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*Persons to be included on FERC's service list are indicated with an asterisk. NERC requests waiver of FERC's rules and regulations to permit the inclusion of more than two people on the service list.

IV. BACKGROUND

a. Regulatory Framework

By enacting the Energy Policy Act of 2005,[12] Congress entrusted FERC with the duties of approving and enforcing rules to ensure the reliability of the Nation's bulk power system, and with the duties of certifying an electric reliability organization ((ERO) that would be charged with developing and enforcing mandatory Reliability Standards, subject to FERC approval. Section 215 of the FPA states that all users, owners, and operators of the bulk power system in the United States will be subject to FERC-approved Reliability Standards.

Section 215(d)(5) of the FPA authorizes FERC to order the ERO to submit a new or modified Reliability Standard. However, it does not negate the requirements in

[12] 16 U.S.C. § 824o (2011).

Section 215(c)(2)(D) the ERO must use to develop that standard—that is, "a process that provides for reasonable notice and opportunity for public comment, due process, openness, and balance of interests." Pursuant to Section 215(d)(2) of the FPA and Section 39.5(c) of FERC's regulations, FERC will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard. In Order No. 693, FERC noted that it would defer to the "technical expertise" of the ERO with respect to the content of a Reliability Standard and explained that, through the use of directives, it provides guidance but does not dictate an outcome. Rather, it will consider an equivalent alternative approach provided that the ERO demonstrates that the alternative will address FERC's underlying concern or goal as efficiently and effectively as FERC's proposal, example, or directive.[13]

b. Basis for Approval of Proposed Reliability Standards

[13] *See, e.g.*, the following paragraphs from Order No. 693: P 31. We emphasize that we are not, at this time, mandating a particular outcome by way of these directives, but we do expect the ERO to respond with an equivalent alternative and adequate support that fully explains how the alternative produces a result that is as effective as or more effective that FERC's example or directive. . .; P 186. Thus, in some instances, while we provide specific details regarding the Commission's expectations, we intend by doing so to provide useful guidance to assist in the Reliability Standards development process, not to impede it.[] We find that this is consistent with statutory language that authorizes FERC to order the ERO to submit a modification "that addresses a specific matter" if FERC considers it appropriate to carry out Section 215 of the FPA.[] In the Final Rule, we have considered commenters' concerns and, where a directive for modification appears to be determinative of the outcome, FERC provides flexibility by directing the ERO to address the underlying issue through the Reliability Standards development process without mandating a specific change to the Reliability Standard. Further, FERC clarifies that, where the Final Rule identifies a concern and offers a specific approach to address the concern, we will consider an equivalent alternative approach provided that the ERO demonstrates that the alternative will address FERC's underlying concern or goal as efficiently and effectively as FERC's proposal; P 187. Consistent with Section 215 of the FPA and our regulations, any modification to a Reliability Standard, including a modification that addresses a Commission directive, must be developed and fully vetted through NERC's Reliability Standards Development Process. FERC's directives are not intended to usurp or supplant the Reliability Standard development procedure. Further, this allows the ERO to take into consideration the international nature of Reliability Standards and incorporate any modifications requested by our counterparts in Canada and Mexico. Until the Commission approves NERC's proposed modification to a Reliability Standard, the preexisting Reliability Standard will remain in effect.

Section 39.5(a) of FERC's regulations requires the ERO to file with FERC for its approval each Reliability Standard that the ERO proposes to become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes to be made effective. FERC has the regulatory responsibility to approve standards that protect the reliability of the bulk power system. In discharging its responsibility to review, approve, and enforce mandatory Reliability Standards, FERC is authorized to approve those proposed Reliability Standards that meet the criteria detailed by Congress:

> [FERC] may approve, by rule or order, a proposed reliability standard or modification to a reliability standard if it determines that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

Order No. 672 provides guidance on the factors FERC will consider when determining whether proposed Reliability Standards meet the statutory criteria. Each of those factors is addressed below in Section V.a.

c. Reliability Standards Development Procedure

NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC *Standard Processes Manual*.[14] In its ERO Certification Order, FERC found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus satisfies certain of the criteria for approving Reliability Standards. The development process is open to any person or entity with a legitimate interest in the reliability of the bulk power

[14] FERC approved the new *Standard Processes Manual* on September 3, 2010 (FERC Docket No. RR10-12-000), which replaces the *Reliability Standards Development Procedure Version 7* in its entirety. Both the *Reliability Standards Development Procedure Version 7* and, when it was approved, the *Standard Processes Manual*, were used to develop the proposed FAC-003-2 Reliability Standard.

system. NERC considers the comments of all stakeholders, and a vote of stakeholders and the NERC Board of Trustees is required to approve a Reliability Standard before the Reliability Standard is submitted to FERC for approval. FAC-003-2 was approved by the NERC Board of Trustees on November 3, 2011.

V. JUSTIFICATION FOR APPROVAL OF THE PROPOSED RELIABILITY STANDARD

This section summarizes the development of the proposed FAC-003-2 Reliability Standard, describes the reliability objectives to be achieved by the standard, explains the development history of the standard, and documents how the standard meets the criteria for approval set by FERC. NERC, in its analysis of the proposed standard, determined that it is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

The final discussion in this section provides the stakeholder ballot results and explains how other key issues were considered and addressed by the Standard Drafting Team.

a. Basis and Purpose of Reliability Standard FAC-003-2 — Transmission Vegetation Management

The primary purpose of the proposed FAC-003-2 standard is to maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located within a transmission ROW and minimize encroachments from vegetation not located on a ROW, thus reducing the risk of vegetation-related outages that could lead to Cascading, uncontrolled separation, or instability. Major outages and operational problems have resulted from contact between vegetation and transmission lines located on many types of lands and reflecting many ownership situations. FAC-003-2 is primarily applicable to overhead transmission lines operated at 200 kV or higher, overhead transmission lines operated below 200 kV identified by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit ("IROL") under NERC Reliability Standard FAC-014, and overhead transmission lines operated below 200 kV identified as a Major Western Electricity Coordinating Council ("WECC") Transfer Path in the Bulk Electric System by WECC to prevent those vegetation-related outages that could lead to Cascading. Because vegetation growth is continual and always present, unmanaged vegetation poses an increasing outage risk over time. If vegetation is not properly managed to avoid encroachments, a contact will eventually occur that could result in a sustained outage.

The proposed FAC-003-2 standard includes seven requirements. The requirements are summarized below.

> **Requirement R1** requires that the Transmission Owner must manage vegetation to prevent encroachments into the MVCD for all lines associated with IROLs and Major WECC Transfer Paths. It provides specific types of encroachments that must be avoided.
>
> **Requirement R2** requires that the Transmission Owner must manage vegetation to prevent encroachments into the MVCD for all other transmission lines that are applicable under this standard. It also provides specific types of encroachments that must be avoided.
>
> **Requirement R3** requires the Transmission Owner to have documentation describing its chosen approach(es) for managing vegetation. The approach must consider the movement of the conductor, as well as growth rate, control method, and inspection frequency.
>
> **Requirement R4** mandates that when a Transmission Owner has observed a vegetation condition that is likely to produce a Fault, it must notify the control center with switching authority for that transmission line of the condition.
>
> **Requirement R5** specifies that a Transmission Owner constrained from performing vegetation management work must take corrective actions to prevent encroachments that would put the line at risk.

Requirement R6 states that the Transmission Owner must inspect 100% of its applicable lines at least once per calendar year, with no more than 18 months between inspections.

Requirement R7 requires that the Transmission Owner must complete 100% of its annual vegetation work plan for applicable lines. It provides for documented modifications to the plan (some of which are listed as examples in the requirement), provided that such modifications do not allow encroachment of vegetation into the MVCD.

The proposed standard presents a comprehensive approach to vegetation management by using three types of requirements to provide a defense-in-depth structure to reduce the likelihood of vegetation-related outages that could lead to Cascading:

- **Performance-based requirements,** which define a particular reliability objective or outcome to be achieved. Requirements R1 and R2 are performance-based requirements.

- **Risk-based requirements,** which are preventive requirements to reduce the risks of failure to acceptable tolerance levels. Requirements R4, R5, R6, and R7 are risk-based requirements.

- **Competency-based requirements,** which define a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. Requirement R3 is a competency-based requirement.

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a reliability standard has a role in reducing the risk of system failures, and that these roles are complementary and reinforcing. This standard uses a defense-in-depth approach to maintain the reliability of the electric transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (MVCD) (Requirements R1 and R2);

- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor movement , and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (Requirement R3);

- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (Requirement R4);

- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (Requirement R5);

- Requiring inspections of vegetation conditions to be performed annually (Requirement R6); and

- Requiring that the annual work needed to prevent flash-over is completed (Requirement R7).

Requirement R3 serves as the first line of defense in maintaining the reliability of the electric transmission system by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. Requirements R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. Requirement R6, which requires inspections, is both a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). Requirement R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

b. Improvements to FAC-003 in this Revision

The currently-effective FAC-003-1 Reliability Standard includes four requirements. As discussed above, the proposed FAC-003-2 standard includes seven requirements, which together present a comprehensive approach to vegetation management using a defense-in-depth strategy. The following paragraphs explain the changes made and how the new standard improves reliability when compared to the existing standard. A summary of the following paragraphs is contained in the FAC-003-1 Mapping to Proposed NERC Reliability Standard FAC-003-2 document provided in **Exhibit D.**

FAC-003-1, Requirement R1

Requirement R1 of the currently-effective FAC-003-1 reads as follows:

> *R1 The Transmission Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the Transmission Owner's objectives, practices, approved procedures, and work specifications.*

This requirement has been replaced by requirement R3 in the proposed FAC-003-2 standard, which reads:

> *R3 Each Transmission Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that include(s) the following:*

Requirement R3 of FAC-003-2 is functionally equivalent to Requirement R1 of FAC-003-1, but offers several improvements.

Requirement R1 of FAC-003-1 mandates the preparation and maintenance of a TVMP. However, the Measure for Requirement R1 refers to having a "documented TVMP," which is not consistent with the requirement itself (with the exception of R1.2, which does require the creation of documentation). The sub-requirements of R1 (which are discussed further in later paragraphs) also refer in some cases to having documentation but in other cases as characteristics.

Requirement R3 of FAC-003-2 corrects these inconsistencies by requiring each Transmission Owner to have documented records indicating the way the entity prevents the encroachment of vegetation into the MVCD of its applicable lines. The proposed requirement is clear and unambiguous. The measure is consistent with the requirement, and clearly indicates that documents are required to demonstrate compliance, and that the documents must be sufficiently clear and complete to show that the entity can meet its obligations when considering the factors specified in the sub-requirements (discussed further in later paragraphs).

Additionally, the new requirement is written in a manner that provides additional flexibility. While the version one requirement mandates the inclusion of “objectives, practices, approved procedures, and work specifications,” the new standard requires “documented maintenance strategies or procedures or processes or specifications.” This new wording using the coordinating conjunction “or” ensures that Transmission Owners are not required to convert their existing approaches into any particular format simply for the sake of meeting a requirement. Rather, the Transmission Owner is given the discretion to determine how best to prevent the encroachment of vegetation into the MVCD. This could be through the use of a specification (*e.g.*, values analogous to the version one concept of “Clearance 1”), or through any of the other approaches (such as an overall strategy to remove all vegetation from within the Right of Way). This modification allows for the use of valid approaches that might have been considered unacceptable under the previous, more prescriptive language in version one of the standard.

FAC-003-1, Sub-requirement R1.1

Sub-requirement R1.1 of the currently-effective FAC-003-1 reads as follows:

> *R1.1 The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the Transmission Owner’s transmission lines.*

This sub-requirement has been replaced by Requirement R6 in the proposed FAC-003-2, which reads:

> *R6. Each Transmission Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW.*

Requirement R6 of FAC-003-2 is similar to sub-requirement R1.1 of FAC-003-1, but offers several improvements.

Sub-requirement R1.1 of FAC-003-1 requires the creation of an inspection schedule, and specifies criteria against which a schedule can be judged for completeness. However, it does not mandate that entities implement the schedule and perform the inspections. The measure for R1.1 indicates that the entity must have performed the inspections.

As an improvement to the standard that reduces risks, Requirement R6 of FAC-003-2 specifically requires the Transmission Owner to inspect 100% of its applicable lines at least once per calendar year. The proposed Requirement R6 is clear and unambiguous. The measure is consistent with the requirement, and clearly indicates that evidence of performance is required to demonstrate compliance. Examples of acceptable evidence are provided, such as completed and dated work orders, dated invoices, or dated inspection records.

FAC-003-1, Sub-requirements R1.2 and R 1.2.1

Sub-requirements R1.2 and R1.2.1 of the currently-effective FAC-003-1 standard reads as follows:

> *R1.2. The Transmission Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors,*

taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the Transmission Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

> *R1.2.1. Clearance 1 — The Transmission Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.*

Sub-requirements R1.2 and R 1.2.1 of FAC-003-1 have been replaced by Requirement R3, parts 3.1 and 3.2, in FAC-003-2, which reads:

R3 Each Transmission Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following

> *R3.1 Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;*
>
> *R3.2 Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.*

The proposed Requirement R3 and parts 3.1 and 3.2 are functionally equivalent to the Version 1 Sub-requirement R1.2 and R1.2.1.

In summary, FAC-003-1, sub –requirements R1.2 and 1.2.1 establish a variable clearance distance (Clearance 1) to which the Transmission Owner must manage in order to avoid encroachments that might occur due to local conditions or time between vegetation management actions. The standard does not mandate an explicit value or mathematical calculation to determine Clearance 1, relying on the judgment of the Transmission Owner to determine this value, with the only criterion for acceptance being that Clearance 1 must be some undefined amount larger than the minimum flashover distance.

Requirement 3, parts 3.1 and 3.2 of FAC-003-2 provide the same flexibility as the currently-effective standard. While the proposed standard does not explicitly identify a "Clearance 1," it continues to give the Transmission Owner the responsibility for avoiding encroachments by requiring the Transmission Owner to consider, among other things, conductor movement, vegetation growth rates, vegetation control methods, and inspection frequency in their documented maintenance strategies, procedures, processes, or specifications to prevent the encroachment of vegetation into the MVCD. In effect, the standard still retains the same obligations defined by "Clearance 1," but does not require the documentation of a specific numerical value. Instead, it offers alternative ways to specify how the reliability objective of this requirement will be met. The standard allows for entities (if they so choose) to retain the concept of a "Clearance 1" as part of the specifications they use to manage vegetation; however, it does not require it. Instead, entities can define their methods for meeting the reliability objective through process, procedures, specifications, or strategy documents (or any combination of those elements).

FAC-003-1, Sub-requirements R1.2.2, R1.2.2.1, and R.1.2.2.2

Sub-requirements R1.2.2, R1.2.2.1, and R.1.2.2.2 of FAC-003-1 read as follows:

R1.2.2. Clearance 2 — The Transmission Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors *under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage.*

These Transmission Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (Guide for Maintenance Methods on Energized Power Lines) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

> *R1.2.2.1 Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.*
>
> *R1.2.2.2 Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.*

Sub-requirements R1.2.2, R1.2.2.1, and R.1.2.2.2 of FAC-003-1 have been replaced by Requirements R1 and R2 of FAC-003-2, which read:

R1. Each Transmission Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below [Violation Risk Factor: High] [Time Horizon: Real-time]:

> *1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage*

R2. Each Transmission Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below [Violation Risk Factor: Medium] [Time Horizon: Real-time]:

> *1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,*

Requirements R1 and R2 of FAC-003-2 are similar to sub-requirements R1.2.2, R1.2.2.1, and R.1.2.2.2 of FAC-003-1, but offer several improvements.

Sub-requirements R1.2.2, R1.2.2.1, and R1.2.2.2 of FAC-003-1 direct the specification of a "Clearance 2," but do not require entities to ensure that vegetation does not encroach within that clearance, or take any action related to actually manage vegetation, other than specifying the value. The measure for R1.2 is consistent with the requirement in that it only measures whether the entity documented the establishment of "Clearance 2." Therefore, the requirement and the measure provide limited value to reliability, as they are primarily designed only to ensure that the entity knows the flashover distance, not take action related to it.

Requirements R1 and R2 of FAC-003-2 significantly expand sub-requirements R1.2.2, R1.2.2.1, and R.1.2.2.2 of FAC-003-1 by requiring Transmission Owners to manage vegetation to prevent encroachments, with a violation occurring upon the observation of an encroachment into the MVCD. This effectively duplicates the concept of "Clearance 2," but requires actual vegetation management rather than documentation of the clearance. Additionally, the standard replaces the use of IEEE Standard 516-2003 (identified by the Commission in Order No. 693 as not appropriate for reliability purposes) with the use of the Gallet Equation to determine the MVCD. The Gallet Equation is an established method for calculating the flashover distance for various voltages, altitudes, and atmospheric conditions. This provides calculated flashover distances between transmission conductors and vegetation that better represent the conditions that occur on the transmission corridor.

Finally, in order to eliminate commingling of higher risk reliability objectives and lesser risk reliability objectives (as discussed in the FERC May 18, 2007 Order on

Violation Risk Factors[15]) the proposed standard separates the concept and objective selected in the "Clearance 2" value into two distinct requirements – those that are related to lines that are either an element of an IROL or an element of a Major WECC Transfer Path (Requirement R1), and those that are not (Requirement R2). This expands the coverage of the standard to those facilities essential to the reliable operation of the bulk electric system and helps ensure that entities properly manage the risk to reliability associated with specific actions.

It is important to note that there are conditions or scenarios that may lead to encroachments outside the Transmission Owner's control. Accordingly, the requirements include a footnote that clarifies such conditions or scenarios. This footnote does not exempt the Transmission Owner from responsibility for encroachments caused by activities performed by their own employees or contractors, but it does exempt them from responsibility when other human activities, animal activities, or other environmental conditions outside their control lead to an encroachment that otherwise would not have occurred.

FAC-003-1, Sub-requirement R1.3

Sub-requirement R1.3 of FAC-003-1 reads as follows:

R1.3 All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner, to perform their duties.

The concepts from this sub-requirement have been eliminated from the proposed standard because it is unclear what "appropriate" qualifications are or how an entity

[15] *North American Electric Reliability Corporation, Order on Violation Risk Factors,* 119 FERC ¶ 61,145 (2007).

would determine them to be "appropriate." More importantly, as the definition of "appropriate" is established entirely by the entity that is subject to compliance with the standards, the requirement is effectively meaningless – a conceptually equivalent translation of the requirement is "the entity shall do what the entity decides to do." Given the shortcomings in the current language, and the difficulty in establishing objective but non-prescriptive criteria relative to training for this particular requirement, the concepts were not carried forward to the proposed standard. This elimination has no impact on the level of reliability under the proposed standard relative to the current standard.

FAC-003-1, Sub-requirement R1.4

Sub-requirement R1.4 of FAC-003-1 reads as follows:

> *R1.4 Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner is restricted from attaining the clearances specified in Requirement 1.2.1.*

Sub-requirement R1.4 of FAC-003-1 has been replaced by Requirement R5 of FAC-003-2, which reads:

> *R5. When a Transmission Owner is constrained from performing vegetation work on applicable transmission lines operating within their Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the Transmission Owner shall take corrective action to ensure continued vegetation management to prevent encroachments*

Requirement R5 of FAC-003-2 is similar to the sub-requirement R1.4 of FAC-003-1, but offers several improvements.

Sub-requirement R1.4 of FAC-003-1 requires the creation of mitigation measures to address locations on the Right-of-Way where the Transmission Owner is restricted from attaining the specified clearances. However, it does not mandate that entities implement mitigation measures. The measure for R1.4 indicates that the entity must have documented the locations identified on the Right-of-Way where the Transmission Owner was restricted from attaining the specified clearances. The measure also requires the documentation of the mitigation measures taken, which is inconsistent with the requirement.

Requirement R5 of FAC-003-2 specifically requires corrective action to be taken in cases where a Transmission Owner is constrained from performing vegetation work such that the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan. The proposed requirement is clear and unambiguous. The measure is consistent with the requirement, and clearly indicates that evidence of performance is required to demonstrate compliance. Examples of acceptable evidence are provided, such as initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized.

FAC-003-1, Sub-requirement R1.5

Sub-requirement R1.5 of FAC-003-1 reads as follows:

> *R1.5. Each Transmission Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.*

Sub-requirement R1.5 of FAC-003-1 has been replaced by requirement R4 of FAC-003-2, which reads:

> *R4. Each Transmission Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when*

the Transmission Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment.

Requirement R4 of FAC-003-2 is similar to sub-requirement R1.5 of FAC-003-1, but offers several improvements.

Sub-requirement R1.5 of FAC-003-1 requires the creation of a process for communicating imminent threats where vegetation conditions could lead to a transmission line outage. However, it does not mandate that entities implement the process and communicate the threat. The measure for R1.5 indicates that the entity must have documentation of their process. This is consistent with the requirement; however, the requirement and the measure only provide limited value to reliability, as they are primarily designed only to ensure that the entity has a process, not take action related to the process.

Requirement R4 of FAC-003-2 requires Transmission Owners, without any intentional time delay, to notify the control center holding switching authority for the associated applicable line when the Transmission Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment. The proposed requirement is clear and unambiguous. The measure is consistent with the requirement, and clearly indicates that evidence of performance is required to demonstrate compliance. Examples of acceptable evidence are provided, such as control center logs, voice recordings, switching orders, clearance orders, and subsequent work orders.

The proposed requirement is clear and unambiguous. The proposed standard replaces the term "immediate," which is impractical at best, with the phrase "without any intentional time delay." The use of "without any intentional time delay" still requires timely notification, but addresses situations where "immediate" communication is impossible or impractical (for example, when an observer is in a remote area without cell phone service). The new language correctly focuses on the desire to communicate in a timely fashion, without attempting to draw any arbitrary deadlines or include impractical absolutes.

FAC-003-1, Requirement R2

Requirement R2 of FAC-003-1 reads as follows:

> *R2. The Transmission Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.*

Requirement R2 of FAC-003-1 has been replaced by requirement R7 of FAC-003-2, which reads:

> *R7. Each Transmission Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include*
>
> - *Change in expected growth rate/ environmental factors*
> - *Circumstances that are beyond the control of a Transmission Owner*
> - *Rescheduling work between growing seasons*
> - *Crew or contractor availability/ Mutual assistance agreements*
> - *Identified unanticipated high priority work*
> - *Weather conditions/Accessibility*
> - *Permitting delays*

- *Land ownership changes/Change in land use by the landowner*
- *Emerging technologies*

Requirement R7 of FAC-003-2 is similar to Requirement R2 of FAC-003-1. Requirement R2 of the existing FAC-003-1 standard requires the creation and implementation of an annual vegetation management plan and a process for documenting and tracking the execution of the plan. However, it does not mandate that entities plan to prevent encroachments into the MVCD, but simply that they implement whatever is included in the plan. The measure is focused on demonstrating that the plan has been executed.

Requirement R7 of the new FAC-003-2 requires the plan be executed such that no vegetations encroachments occur within the MVCD. There are practical exceptions, however (for example, where land ownership changes may have resulted in the utility not possessing the property rights needed). In these cases, the entity may modify its plan; however, at no point can it modify its plan such that it would allow encroachment of vegetation into the MVCD. This new requirement raises the required level of performance by requiring 100% of the plan be completed, and provides an explicit method for determining the percentage that was completed. The proposed requirement is clear and unambiguous. The measure is consistent with the requirement, and clearly indicates that evidence of performance is required to demonstrate compliance. Examples of acceptable evidence are provided, such as a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records.

FAC-003-1, Requirements R3, R4, and associated sub-requirements

Requirements R3, R4, and associated sub-requirements of FAC-003-1 read as follows:

R3. The Transmission Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission Owner to have been caused by vegetation.

> *R3.1. Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24-hour period.*
>
> *R3.2. The Transmission Owner is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).*
>
> *R3.3. The outage information provided by the Transmission Owner to the RRO, or the RRO's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.*
>
> *R3.4. An outage shall be categorized as one of the following:*
>
> > *R3.4.1. Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;*
> >
> > *R3.4.2. Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;*
> >
> > *R3.4.3. Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.*

R4. The RRO shall report the outage information provided to it by Transmission Owner's, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the RRO as a result of any of the reported outages.

Requirements R3, R4, and associated sub-requirements of FAC-003-1 are associated with monitoring and compliance. Accordingly, they have been moved to the compliance section of the proposed standard:

Periodic Data Submittal: The Transmission Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the Transmission Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- *The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.*

A Sustained Outage is to be categorized as one of the following:

- *Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;*
- *Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;*
- *Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;*
- *Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;*
- *Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;*
- *Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.*

- *Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.*

The Regional Entity will report the outage information provided by Transmission Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

This transfer of a reporting requirement to the Compliance portion of the standards remains enforceable under NERC's Rules of Procedure. NERC's authority to require such data is described in Section 400.3 of the Rules of Procedure:

> *Data Access — All bulk power system owners, operators, and users shall provide to NERC and the applicable regional entity such information as is necessary to monitor compliance with the reliability standards. NERC and the applicable regional entity will define the data retention and reporting requirements in the reliability standards and compliance reporting procedures.*

An entity that is not in compliance with this rule must take specific actions, and NERC has certain courses of action it may undertake as necessary to ensure the entity complies with the Rules, as specified in Section 100 of the NERC Rule of Procedure:

> *Any entity that is unable to comply or that is not in compliance with a NERC rule of procedure shall immediately notify NERC in writing, stating the rule of concern and the reason for not being able to comply with the rule.*
>
> *NERC shall evaluate each case and inform the entity of the results of the evaluation. If NERC determines that a rule has been violated, or cannot practically be complied with, NERC shall notify the applicable governmental authorities and take such other actions as NERC deems appropriate to address the situation.*

Accordingly, NERC believes it has sufficient authority and recourse to ensure such data continues to be submitted. Additionally, if necessary, NERC can compel entities to provide such data separately as part of a Section 1600 data request, pursuant to Section 1600 of the NERC Rules of Procedure, which has similar provisions.

Additional Requirements

In addition to the disposition and transfer of requirements from the previous standard as described above, Requirements R1 and R2 of FAC-003-2 are additional requirements that were added to the standard:

> *R1. Each Transmission Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below:*
>
> 1. *An encroachment into the MVCD as shown in FAC-003-Table 2, observed -time, absent a Sustained Outage ,*
> 2. *An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,*
> 3. *An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,*
> 4. *An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.*
>
> *R2. Each Transmission Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below:*
>
> 1. *An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage,*
> 2. *An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,*
> 3. *An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,*
> 4. *An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage*

Requirements R1 and R2 of FAC-003-2 are significant improvements not included in FAC-003-1. These requirements are focused on the results of managing vegetation and ensuring that 1) encroachments do not occur, and 2) sustained outages do not occur. The proposed requirements are clear and unambiguous. The measure is consistent with the requirement, and clearly indicates that evidence of performance is required to demonstrate compliance. Examples of acceptable evidence are provided. These include completed and dated work orders, dated invoices, or dated inspection records.

As discussed previously with regard to "Clearance 2," these new requirements provide that the Transmission Owner must manage vegetation to prevent encroachments, rather than simply document the clearance. The standard replaces the use of IEEE Standard 516-2003 with the use of the Gallet Equation to determine the MVCD. Additionally, in order to eliminate commingling of higher-risk reliability objectives and lesser-risk reliability objectives, the standard has separated the concept of "Clearance 2" into two distinct requirements – those that are related to line(s) that are either an element of an IROL or an element of a Major WECC Transfer Path, and those that are not. This helps ensure that entities properly understand the risk to reliability associated with specific actions, and aligns the standard and associated VRFs with Commission guidelines.

c. Enforceability of the Proposed FAC-003-2 Reliability Standard

The proposed Reliability Standard contains measures that support each standard requirement by clearly identifying what is required and how the requirement will be enforced. The VSLs also provide further guidance on the way that NERC will enforce the requirements of the standard. A component of enforceability of this proposed standard is the use of appropriate compliance monitoring tools and the discovery methods as laid out in the Compliance Monitoring and Enforcement Program ("CMEP").

Requirements R1 and R2 require the Transmission Owner manage vegetation to prevent encroachments into the MVCD. The measures for these requirements are identical:

> *Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in (the requirement). Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments.*

In other words, the burden of proof to show records indicating the requirements were not violated is held by the Transmission Owner. The VSLs recommended for Requirements R1 and R2 are "pass or fail" evaluations; if an entity does not manage vegetation to prevent encroachments, then it fails the requirement (R1 or R2, as applicable to the given scenario). Such failures would be identified using NERC's normal Compliance Monitoring and Enforcement processes – primarily through periodic data submittals, self-certification and self-reporting, but also through audits, spot-checking, compliance violation investigations, and complaints as appropriate.

Requirements R1 and R2 include a general footnote that describes some cases where an entity might not be held to the standard (for example, during natural disasters). However, these limitations only apply to those circumstances that are beyond the control of the Transmission Owner or the other duly delegated registered entities, affiliates or contractors that fulfill reliability responsibilities on behalf of the Transmission Owner. Transmission Owners have options as to how to appropriately delegate reliability tasks to ensure accountability with other registered entities. For example, the use of Joint Registration Organization, Coordinated Functional Registration agreements, or other duly executed legal agreements clearly delineate reliability task responsibility. Transmission Owners are further responsible for any contract work associated with maintaining their system and facilities.

Requirement R3 requires the Transmission Owner to have documentation describing its chosen approach(es) for managing vegetation. The approach must consider the movement of the conductor, as well as growth rate, control method, and inspection frequency. The measure for this requirement is as follows:

> *The maintenance strategies or procedures or processes or specifications provided demonstrate that the Transmission Owner can prevent encroachment into the MVCD considering the factors identified in the requirement.*

In this case, the Transmission Owner is obligated to show documentation, and that documentation must be sufficient to satisfy the auditor that the information contained in that documentation is sufficient that the Transmission Owner can use it to prevent encroachment into the MVCD. The difference in sizes of applicable entities, the nature of vegetation, and the number of techniques available to applicable entities to manage it require that the measure allow for sufficient flexibility in approach. For example, vegetation management in Arizona is likely to be much different from that in West Virginia. Similarly, the approach used to manage a small system may be described in a few short sentences, while the approach used on a much larger system might require several volumes to describe. Auditors will have to use judgment to evaluate the appropriateness of the documentation provided given the particular circumstances of the entity being audited. To guide them in this, the Violation Severity Levels provided for

Requirement R3 gradate the severity of a violation based on the completeness of the information provided. In this case, failures of the requirement would likely be identified during review of the document(s) as submitted in response to a data request to support an audit, spot-check, or a self-certification. The document(s) the requirement describes can generally be understood to encompass the broad strategy, direction and goals supported by analysis and information peculiar to the geographical area of the Transmission Owner and the characteristics of its system. This document generally should be the foundation for the detail and supporting evidence required in requirements 4 through 7. As a competency based requirement, this is the cornerstone of the Transmission Owner's program to ensure vegetation management is implemented to ensure no encroachment.

Requirement R4 states that when a Transmission Owner observes a vegetation condition that is likely to produce a fault, it must notify the control center with switching authority for that transmission line of the condition. The measure for this requirement is:

> *Each Transmission Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders.*

As with R1 and R2, the burden of proof to show records indicating the requirement was not violated is held by the Transmission Owner. The VSLs provided for Requirement R4 gradate the severity of a violation based on whether or not any delay in communicating the information was intentional or not. Auditors will have to use judgment to evaluate the manner in which the requirement was met given the particular circumstances of the entity being audited, but it is expected that an entity that does not make this reporting a top priority would be in violation of the standard. Generally speaking the requirement to notify without intentional delay can be understood to include an immediate (within 1 hour of the observation) communication notwithstanding a safety issue to the personnel, other immediate priority maintenance functions to ensure reliability or system stability, or communications equipment failure that precludes immediate communication. Such violations would be identified using NERC's normal Compliance Monitoring and Enforcement processes – primarily through self-certification and self-reporting, but also through audits, compliance violation investigations, and complaints as appropriate.

Requirement R5 states that a Transmission Owner prevented from performing vegetation management work must take corrective actions to prevent encroachments that would put the line at risk. The measure for this requirement is

> *Each Transmission Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized.*

In this case, the Transmission Owner must show proof that it took corrective action when necessary. In the event that a Transmission Owner is unable, for whatever reason, to prevent or clear encroachments in the MVCD, it must de-energize or de-rate the line to reduce the MVCD to preclude an encroachment, or will be found in violation of this requirement as well as requirement #1 or #2 as applicable. The VSL recommended for Requirement R5 is a "pass or fail" evaluation; if an entity does not take corrective action, then it fails the requirement. Such failures would be identified using NERC's normal Compliance Monitoring and Enforcement processes – primarily through self-certification and self-reporting, but also through audits, spot-checking, and compliance violation investigations and complaints as appropriate.

Requirement R6 mandates the Transmission Owner to inspect 100% of its applicable lines at least once per calendar year, with no more that 18 months between inspections. The measure for this requirement is

> *Each Transmission Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records.*

In this case, the Transmission Owner must show proof it inspected all of its lines within the calendar year as described. This requirement can be understood to require a document to account for the inspection of the lines over the period of the time specified and status reports to demonstrate the progress of work performed to meet the requirement. The VSLs recommended for Requirement R6 are gradated based on the percentage of lines not inspected. Such failures would be identified using NERC's normal Compliance Monitoring and Enforcement processes – primarily through self-certification and self-reporting, but also through audits, spot-checking, compliance violation investigations, and complaints as appropriate.

Requirement R7 states the Transmission Owner must complete 100% of its annual vegetation work plan for applicable lines, and provides for modifications to the plan for a number of reasons (some of which are listed as examples in the requirement), but indicates that such modifications must not allow encroachment of vegetation into the MVCD. The requirement essentially allows a Transmission Owner to have a dynamic vegetation work plan, as long as the Transmission Owner meets the obligations in its plan and the plan serves its primary function of avoiding encroachments. The measure for this requirement is

> *Each Transmission Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records.*

In this case, the Transmission Owner must show proof that it completed its plan. An entity unable to produce a plan will be unable to demonstrate compliance with the standard, resulting in a violation of the requirement. Although the standard does not explicitly require the creation of a plan, entities will not be able to comply with the requirement without having a documented plan. It should be noted that the documented plan is not necessarily a single binder that includes all aspect of vegetation management; it may be a collection of documents. Entities may meet this requirement through several methods including on-line manuals, paper documents, handbooks, guidelines, work orders, or pieces of information, provided the information clearly demonstrates the requirement has been met.

Because of the dynamic nature of vegetation, the plan must also be dynamic. While in theory this might allow an entity to modify its plan to avoid compliance risk, such modification would not eliminate the obligation that the modified plan be executed to avoid encroachment of vegetation into the MVCD. Any such encroachment would be a violation of R1 or R2, and any changes to the plan that resulted in such encroachment would be a violation of R7. The VSLs recommended for Requirement R7 are gradated based on the percentage of the final plan not completed. Such failures would be identified using NERC's normal Compliance Monitoring and Enforcement processes – primarily through self-certification and self-reporting, but also through audits, spot-checking, compliance violation investigations, and complaints as appropriate. In order for auditors to make appropriate judgments as to the completed plan and any modifications, the initial work plan may be requested via a self certification or data submittal prior to its initiation and then compared to the completed plan at the end of the time period.

As discussed above, the measures and VSLs provide clarity regarding how the requirements will be enforced, and ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party. Appropriate use of compliance monitoring tools will be utilized and specified in the Annual Compliance Monitoring and Enforcement Program Implementation Plan and Actively Monitored List.

d. FERC Directives Addressed in the Proposed FAC-003-2 Standard

The drafting team responsible for the development of FAC-003-2 addressed seven directives issued by the Commission in Order No. 693[16] as part of NERC Project 2007-07 Vegetation Management. These directives are presented below with the resolutions proposed by the drafting team. The text of the complete proposed standard FAC-003-2 is included in Exhibit A.

> *Paragraph 706 of Order 693, sentences 1, 2 and 3 (directive reference number 10098[17]) - We will not direct NERC to submit a modification to the general limitation on applicability as proposed in the NOPR. However, we will require the ERO to address the proposed modification through its Reliability Standards development process. As explained in the NOPR, the Commission is concerned*

[16] *See*, Order No. 693 at PP 706 to 735.

[17] The "directive reference number" refers to the number assigned to a particular regulatory directive in the NERC Standards Issues Database. The reference number is identified in the summary section for each regulatory directive. Each reference number is unique and provides an easy reference for each regulatory directive.

that the bright-line applicability threshold of 200 kV will exclude a significant number of transmission lines that could impact Bulk-Power System reliability.

Proposed FAC-003-2, and the resolution of the issue of applicability in particular, was developed through the Reliability Standards development process. The first draft of the standard proposed to assign the selection of sub-200kV lines to the Reliability Coordinator (rather than the Regional Reliability Organization, as was specified in version 1 of the standard). With the third draft, specific criteria based on the importance of sub-200kV lines were proposed to replace the discretion of the Reliability Coordinator, effectively creating a "bright line" for those facilities operated below 200kV. In the final proposed standard submitted with this petition, these proposed bright-line criteria are substantively unchanged from the third draft. Industry was asked to comment on these proposals through the standard development process, and balloting indicates support for this approach.

NERC believes this to be a superior approach to the previous standard, as it has eliminated the previous "fill-in-the-blank" discretion of the Regional Reliability Organization and now focuses instead on specific criteria to determine the applicability to sub-200kV facilities.

Paragraph 706 of Order 693, sentences 7 and 8 (directive reference number 10099) – We support the suggestions by Progress Energy, SERC and MISO to limit applicability to lower voltage lines associated with IROL and these suggestions should be part of the input to the Reliability Standards development process. Similarly, the ERO should evaluate the suggestions proposed by LPPC, APPA and Avista.

FAC-003-2 adopts the suggestions of Progress Energy, SERC, and MISO, and extends the applicability to address issues specific to the Western Interconnection. The applicability of lines operated below 200kV has been limited to specific cases where lines are critical to reliability by virtue of their being elements included in the determination of an Interconnection Reliability Operating Limit ("IROL") or a part of a Major WECC Transfer Path. In response to the concerns expressed by Avista, the standard does not create a new minimum bright-line threshold of 100kV. By virtue of relying on IROL and Major WECC Transfer Path identification as a proxy for reliability importance, the proposed standard uses an impact-based approach for determining applicability as suggested by LPPC. The suggestion made by APPA and Avista to grant authority to the Regional Entity to determine applicability was considered, conceptually implemented in the first draft of the standard through delegation to the Reliability Coordinator), then ultimately rejected in favor of the use of the IROL and Major WECC Transfer Path identification criteria.

> *Paragraph 708 of Order 693, sentence 3 (directive reference number 10102) - We recognize that many commenters would like a more precise definition for the applicability of this Reliability Standard, and we direct the ERO to develop an acceptable definition that covers facilities that impact reliability but balances extending the applicability of this standard against unreasonably increasing the burden on transmission owners.*

Proposed FAC-003-2 includes a detailed and specific description of the applicability relative to facilities. Criteria used in the applicability focus on the criticality of lines to reliability by virtue of their being elements included in the determination of an IROL or a part of a Major WECC Transfer Path.

> *Paragraph 709 of Order 693, sentences 1 and 2 (directive reference number 10103) - FirstEnergy and Xcel suggest that if the applicability of this Reliability Standard is expanded, the Commission should allow flexibility in complying with this Reliability Standard for lower-voltage facilities, or allow lower-voltage facilities one year before the Reliability Standard is implemented. The ERO should consider these comments when determining when it would request that the modification of this Reliability Standard to go into effect.*

The Implementation Plan for the proposed standard adopts the suggestion of First Energy and Xcel. The standard becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard.

> *Paragraph 721 of Order 693, sentences 1 and 2 (directive reference number Ref 10104) - The Commission continues to be concerned with leaving complete discretion to the transmission owners in determining inspection cycles, which limits the effectiveness of the Reliability Standard. Accordingly, the Commission directs the ERO to develop compliance audit procedures, using relevant industry experts, which would identify appropriate inspection cycles based on local factors.*

Proposed FAC-003-2 now requires the Transmission Owner to perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, *etc.*) at least once per calendar year, with no more than 18 calendar months between inspections. Transmission Owners may inspect more frequently should they need to do so in order to meet the other requirements in the standard, but they may not inspect less frequently.

> *Paragraph 732 of Order 693, sentence 1 (directive reference number 10100) - Accordingly, the Commission directs the ERO to develop a Reliability Standard that defines the minimum clearance needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal land and non-federal land.*

As directed, proposed FAC-003-2 applies to facilities that meet specific criteria, including (but not limited to) those that cross lands owned by federal, state, provincial, public, private, or tribal entities, and specifies the minimum clearance needed to avoid sustained vegetation-related outages. The proposed standard defines MVCD based on the Gallet Equation, a well-known method for specifically calculating the flashover distance for proper insulation coordination. This calculation accounts for wet conditions at various altitudes.

> *Paragraph 734 of Order 693, sentences 1 and 3 (directive reference number 10105) - FirstEnergy suggests that rights-of-way be defined to encompass the required clearance areas instead of the corresponding legal rights, and that the standards should not require clearing the entire right-of-way when the required clearance for an existing line does not take up the entire right-of-way.…Accordingly, the Commission directs the ERO to address this suggestion in the Reliability Standards development process.*

Proposed FAC-003-2 includes a modified definition of "Right-of-Way" to include the statement "[t]he ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria." Similar to FAC-003-1, FAC-003-2 does not require clearing the entire legal limits for a particular parcel of land to ensure reliability. Rather, the standard requires vegetation maintenance to adequately prevent outages from vegetation and requires the Transmission Owner to prevent encroachment within the MVCD in the operational corridor established under the modified ROW definition. This provides the Transmission Owner with flexibility in determining its approach to vegetation management and gives owners the authority to act in the best interest of reliability without mandating any specific strategy (such as clearing the entire width of the ROW).

e. Demonstration that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential and in the public interest

In Order No. 672, FERC identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standard has met or exceeded the criteria:

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound method to achieve that goal.

> Order No. 672 at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cyber security protection.
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> Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

The proposed FAC-003-2 standard achieves the specific reliability goal of maintaining a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission ROW and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

The proposed Reliability Standard contains a technically sound method to achieve that goal by:

- requiring that vegetation be managed to prevent vegetation encroaching into the flash-over distance;
- requiring consideration of conductor movement, vegetation growth rates, vegetation control methods, and inspection frequency when establishing strategies for vegetation management;
- requiring intervention when risks of vegetation contact are identified;

- requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains (such as legal injunctions);
- requiring annual inspections of vegetation conditions to be performed annually; and
- requiring completion of the annual work needed to prevent encroachments.

2. Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.

Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

The proposed Reliability Standard is applicable only to users, owners and operators of the North American bulk-power system, and not others. As identified in the applicability section of the proposed standard, the requirements apply only to Transmission Owners. No other registered entities are required to comply.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.

Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

The proposed Reliability Standard includes a VRF and VSL for each main requirement, which is explained in more detail in Section IV. c, below. Upon approval by FERC, the range of penalties for violations will be based on the applicable VRF and VSL and will be administered based on the sanctions table and supporting penalty determination process described in FERC-approved NERC Sanction Guidelines, Appendix 4B in NERC's Rules of Procedure. Therefore, responsible entities understand the potential impacts of non-compliance with the proposed requirements.

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.

Order No. 672 at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

The proposed Reliability Standard contains measures that support each requirement by clearly identifying what is required and how the requirement will be enforced. These measures, included below, help provide clarity regarding how the requirements will be enforced, and ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

M1. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

M2. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)

M3. The maintenance strategies or procedures or processes or specifications provided demonstrate that the Transmission Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

M4. Each Transmission Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

M5. Each Transmission Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

M6. Each Transmission Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

M7. Each Transmission Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost.

Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

The proposed Reliability Standard achieves its reliability goal effectively and efficiently. Crafting the requirements to address the societal need for reliable service and meet the overall reliability goal for the standard was carefully undertaken using NERC's results-based standards development techniques, and the proposed standard was structured to identify specific objectives to achieve the goal without unduly burdening applicable entities. The standard avoids mandates for specific practices, and instead focuses on the "what" as opposed to the "how." For example, this standard provides the Transmission Owner significant discretion in determining how to manage vegetation, focusing on results rather than process. This approach allows for diverse approaches to vegetation management, through which lessons learned and best practices can be identified and implemented, and overall reliability is buttressed and enhanced.

6. Proposed Reliability Standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect bulk power

> **system reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.**
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> Order No. 672 at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although FERC will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.
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> Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

The proposed Reliability Standard does not reflect a "lowest common denominator" approach. To the contrary, the proposed standard represents a significant improvement over the previous version as described herein. The Standard Drafting Team took measured steps to ensure that the reliability objective of developing and implementing technically sound Transmission Vegetation Management was met and that each requirement provides detail of what is necessary to be addressed in the applicable documentation or methodology.

Additionally, the proposed Reliability Standard was not developed or adopted to protect against the imposition of reasonable expenses. The drafting team considered and evaluated the effect this standard would impose on the impacted entities and determined that no entities would be unduly burdened by the cost to implement its requirements. No special accommodation was made for smaller entities, and the proposed standard will apply equally to all applicable entities in a consistent manner.

7. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one area or approach.

Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

The proposed Reliability Standard applies throughout North America and does not favor one area or approach.

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid.

Order No. 672 at P 332. As directed by section 215 of the FPA, FERC itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

The proposed Reliability Standard does not restrict the available transmission capability or limit use of the bulk-power system in a preferential manner.

9. The implementation time for the proposed Reliability Standards must be reasonable.

Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, FERC will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

The proposed effective date for the FAC-003-2 is the first day of the first calendar quarter that occurs twelve months following the effective date of a Final Rule in this docket. This will allow applicable entities adequate time to ensure compliance with the requirements. Additionally, the proposed standard provides several transition cases and associated timelines to address situations where line classification or asset ownership changes. These transition cases are explained in the proposed Implementation Plan, attached as **Exhibit B**.

10. The Reliability Standard development process must be open and fair.

> Order No. 672 at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.

The proposed Reliability Standard was developed in accordance with NERC's FERC-approved, ANSI- accredited processes for developing and approving Reliability Standards. Section V, *Summary of the Reliability Standard Development Proceedings*, below, details the processes followed to develop the FAC-003-2 standard (for a more thorough review, please see the complete development history included as **Exhibit G**).

These processes included, among other things, multiple comment periods, pre-ballot review periods, and balloting periods. Additionally, all drafting team meetings were properly noticed and open to the public. The initial and recirculation ballots both achieved a quorum and exceeded the required ballot pool approval levels.

11. Proposed Reliability Standards must balance with other vital public interests.

> Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

NERC has identified no competing public interests regarding the request for approval of this proposed Reliability Standard. No comments were received that indicated the proposed standard conflicts with other vital public interests.

12. Proposed Reliability Standards must consider any other relevant factors.

> Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.

No other negative factors relevant to whether the proposed Reliability Standard is just and reasonable were identified.

f. Violation Risk Factors and Violation Severity Levels

The VRFs and VSLs for the proposed standard comport with NERC and FERC guidelines related to their assignment. Discussion of each of these items is included below. For a detailed review of the VRFs, the VSLs, and the analysis of how the VRFs and VSLs were determined using these guidelines, please see **Attachment F**.

The following discussion summarizes the manner in which the VRFs align with FERC's VRF Guidelines 2 through 5. The standard does not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. NERC believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its attention on the reliability impact of the requirements.

Requirement R1 of the standard was assigned a VRF of High. The Requirement states Transmission Owners must manage vegetation for lines that represent a significant risk of cascading, instability, or separation. The VRF is only applied at the Requirement level and each Requirement Part is treated equally. The requirement mandates measurable performance with regard to vegetation management to ensure that the risk of cascading, separation, and instability is minimized. Other requirements with similar performance based outcomes that could lead to cascading carry a High VRF. IROLs and Major WECC Transfer Paths by definition have an increased potential for leading to cascading, separation, or instability. Therefore this requirement was assigned a High VRF. The requirement contains only one objective (which is to manage vegetation of lines that carry increased risk of instability, cascading, or separation) and only one VRF was assigned.

Requirement R2 of the standard was assigned a VRF of Medium. The Requirement states Transmission Owners must manage vegetation for lines that do not represent a significant risk of cascading, instability, or separation. The VRF is only applied at the Requirement level, and each Requirement Part is treated equally. The requirement mandates measurable performance with regard to vegetation management to ensure the risk of equipment damage is minimized. Other requirements with similar performance based outcomes that could lead to equipment damage carry a Medium VRF. Lines that are not IROLs and are not Major WECC Transfer Paths by definition have less potential for leading to cascading, separation, or instability. Therefore this requirement was assigned a Medium VRF. The requirement contains only one objective (which is to manage vegetation of lines that carry minimal risk instability, cascading, or separation) and only one VRF was assigned. While this assignment is lower than the current VRF assigned to R1 of FAC-003-1, NERC believes this to be appropriate, as it aligns with the Commission-approved definitions for VRFs and complies with FERC's guidelines regarding the establishment of these values. Additionally, in order to eliminate commingling of higher risk reliability objectives and lesser risk reliability objectives, this requirement and its associated VRF has been split from Requirement R1. While R1 addresses those violations related to line(s) that are either an element of an IROL or an element of a Major WECC Transfer Path, R2 addresses those that are not. This separation helps ensure entities properly understand the risk to reliability associated with specific actions, as well as aligns the standard and associated VRFs with Commission guidelines.

Requirement R3 of the standard was assigned a VRF of Lower. The Requirement mandates the Transmission Owner to have documented strategies, procedures, processes, or specifications. The VRF is only applied at the Requirement level and each Requirement Part is treated equally. This requirement calls for an entity to have documented strategies, procedures, processes, or specifications. This requirement is administrative in nature, and is consistent with other standards requiring documentation. Failure to have a document is not likely to directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. Development of documents is a requirement that is administrative in nature and is in a planning time-frame that, if violated, would not, under emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. Therefore this requirement was assigned a Lower VRF. R3 contains only one objective (which is to have documents), and only one VRF was assigned. While this assignment is lower than the current VRF assigned to R1 of FAC-003-1, NERC believes this to be appropriate, as it aligns with the Commission-approved definitions for VRFs and complies with FERC's guidelines regarding the establishment of these values.

Requirement R4 of the standard was assigned a VRF of Medium. The Requirement specifies that transmission owners must report vegetation conditions that are likely to cause a Fault to the control center holding switching authority for the associated line. The VRFs are only applied at the Requirement level and there are no Requirement Parts for separate consideration. The requirement mandates notifications that could hinder the ability to effectively monitor and control the bulk electric system. Other requirements with similar outcomes are also assigned Medium VRFs. Failure to report vegetation conditions may affect the ability to effectively monitor and control the Bulk Electric System. Therefore this requirement was assigned a Medium VRF. The requirement contains only one objective (which is to report), and only one VRF was assigned. While this assignment is lower than the current VRF assigned to R1 of FAC-003-1, NERC believes this to be appropriate, as it aligns with the Commission-approved definitions for VRFs and complies with FERC's guidelines regarding the establishment of these values.

Requirement R5 of the standard was assigned a VRF of Medium. The Requirement mandates that a Transmission Owner, when constrained from performing vegetation work that may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, must take corrective action to ensure continued vegetation management to prevent encroachments. The VRF is only applied at the Requirement level and there are no Requirement Parts for separate consideration. The requirement mandates corrective action that, if not taken, could directly affect the electrical state or the capability of the bulk electric system. Other requirements with similar outcomes are also assigned Medium VRFs. Failure to take corrective action could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. Therefore this requirement was assigned a Medium VRF. The requirement contains only one objective (which is to take corrective action), and only one VRF was assigned. While this assignment is lower than the current VRF assigned to R1 of FAC-003-1, NERC believes this to be appropriate, as it aligns with the Commission-approved definitions for VRFs and complies with FERC's guidelines regarding the establishment of these values.

Requirement R6 of the standard was assigned a VRF of Medium. The Requirement specifies that the Transmission Owner must perform a Vegetation Inspection of 100% of its lines at least once per calendar year. The VRFs are only applied at the Requirement level and there are no Requirement Parts for separate consideration. The requirement mandates inspections that, if not performed, could affect the ability to effectively monitor and control the Bulk Electric System. Other requirements with similar outcomes are also assigned Medium VRFs. Failure to perform an inspection could affect the ability to effectively monitor and control the Bulk Electric System. Therefore this requirement was assigned a Medium VRF. The requirement contains only one objective (which is to perform a vegetation inspection), and only one

VRF was assigned. While this assignment is lower than the current VRF assigned to R1 of FAC-003-1, NERC believes this to be appropriate, as it aligns with the Commission-approved definitions for VRFs and complies with FERC's guidelines regarding the establishment of these values.

Requirement R7 of the standard was assigned a VRF of Medium. The Requirement specifies that the Transmission Owner must complete 100% of its annual vegetation work plan. The VRFs are only applied at the Requirement level and there are no Requirement Parts for separate consideration. The requirement mandates completion of work that, if not completed, could affect the electrical state or the capability of the bulk electric system. Other requirements with similar outcomes are also assigned Medium VRFs. Failure to complete the annual vegetation work plan could affect the electrical state or the capability of the bulk electric system. Therefore this requirement was assigned a Medium VRF. The Requirement contains only one objective (which is to complete 100% of the annual vegetation work plan), and only one VRF was assigned. While this assignment is lower than the current VRF assigned to R2 of FAC-003-1, NERC believes this to be appropriate, as it aligns with the Commission-approved definitions for VRFs and complies with FERC's guidelines regarding the establishment of these values.

Regarding the VSLs, they have been developed based on the situations an auditor may find during a typical compliance audit. The following discussions summarize the manner in which the VSLs meet both NERC and FERC guidelines for VSLs.

For Requirement R1, there is an incremental aspect to the violation, and the VSLs follow the guidelines for incremental violations. The standard incorporates a High VSL for failure to prevent encroachment into the MVCD that does not lead to a sustained outage and a Severe VSL for failure to manage vegetation that leads to any of the identified vegetation-related sustained outages. This is a new requirement, and accordingly, it cannot lower the current level of compliance. The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Consistent with the requirement, the proposed VSL uses the same terminology as used in the associated requirement and is based on a single violation and not cumulative violations.

For Requirement R2, there is an incremental aspect to the violation, and the VSLs follow the guidelines for incremental violations. The standard incorporates a High VSL for failure to prevent encroachment into the MVCD that does not lead to a sustained outage and a Severe VSL for failure to manage vegetation that leads to any of the identified vegetation-related sustained outages. This is a new requirement, and accordingly, it cannot lower the current level of compliance. The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Consistent with the requirement, the proposed VSL uses the same terminology as used in the associated requirement and is based on a single violation and not cumulative violations.

For Requirement R3, there is an incremental aspect to the violation, and the VSLs follow the guidelines for incremental violations. The previous standard graded the VSLs based on the completeness of the TVMP. The new VSL is structured similarly, but has omitted the "Low" level - effectively raising the minimum level of compliance. The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Consistent with the requirement, the proposed VSL uses the same terminology as used in the associated requirement, and is based on a single violation and not cumulative violations.

For Requirement R4, there is an incremental aspect to the violation, and the VSLs follow the guidelines for incremental violations. The previous standard does not require actual communication, while the new standard does. Accordingly, this should be treated as a new requirement, and therefore cannot lower the current level of compliance. The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Consistent with the requirement, the proposed VSL uses the same terminology as used in the associated requirement and is based on a single violation and not cumulative violations.

For Requirement R5, the VSL is "binary" (pass/fail). If a Transmission Owner did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk, then a violation had occurred. The only VSL is Severe, and therefore, the VSL cannot result in a lower level of compliance. The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Consistent with the requirement, the proposed VSL uses the same terminology as used in the associated requirement and is based on a single violation and not cumulative violations.

For Requirement R6, there is an incremental aspect to the violation, and the VSLs follow the guidelines for incremental violations. The previous standard does not require actual inspections, while the new standard does. Accordingly, this should be treated as a new requirement, and therefore cannot lower the current level of compliance. The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Consistent with the requirement, the proposed VSL uses the same terminology as used in the associated requirement and is based on a single violation and not cumulative violations.

For Requirement R7, there is an incremental aspect to the violation, and the VSLs follow the guidelines for incremental violations. The VSLs in the previous standard were focused on completeness of the document with the "Severe" VSL only reserved for entities that did not have or implement their plan. The proposed VSLs are graded based on the amount of the plan completed, giving a clear indication that partial completion is still a violation. This provides a level of compliance in excess of what was established by the previous version of the standard. The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. Consistent with the requirement, the proposed VSL uses the same terminology as used in the associated requirement and is based on a single violation and not cumulative violations.

VI. SUMMARY OF THE RELIABILITY STANDARD DEVELOPMENT PROCEEDINGS

a. Development History

The development record for FAC-003-2 is summarized below. **Exhibit E** contains the Consideration of Comments Reports created during the development FAC-003-2. **Exhibit G** contains the complete record of development for FAC-003-2.

i. SAR Development

Project 2007-07 Vegetation Management was initiated on January 9, 2007 for the purpose of reviewing and modifying FAC-003-1. The first draft of the Standards Authorization Request ("SAR") was posted for industry comment from January 15, 2007 to February 14, 2007. Commenters suggested additional enhancements to the SAR, including a request for a reference document to aid in the implementation of the standard. An updated SAR was posted from April 10, 2007 to May 9, 2007. Following minor corrections, the SAR was finalized and posted, a drafting team was assembled, and development of the standard commenced.

ii. Overview of the Standard Drafting Team

When evaluating proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[18] The technical expertise of the ERO is derived from the SDT. For this project, the SDT consisted of 17 industry experts with over 500 years collective experience. The SDT included experts in vegetation management, several registered professional engineers, and industry thought leaders that generously lent their expertise to NERC and other professional organizations such as the Institute of Electrical and Electronics Engineers ("IEEE"). Each individual is considered to be an expert in his field. Members of this standard drafting team provided a diversity of vegetation management experience, ranging across North America, including both the

[18] Section 215(d)(2) of the Federal Power Act; 16 U.S.C. § 824o(d)(2) (2011).

continental United States and Canada. A detailed set of biographical information for each of the team members is included along with the SDT roster in **Exhibit H**.

iii. The First Posting

The first draft of FAC-003-2 was posted for formal comment from October 27, 2008 to November 25, 2008. A mapping document was provided to industry to assist in the review of the standard. Sixty sets of comments were received, representing each of the 10 Industry Segments within NERC's stakeholder structure. Based on the comments received, modifications were made to the standard, including:

- Replacing the Critical Clearance Zone concept found in R4 with a practical field measurement to address commenter's concerns.
- Eliminating the Critical Clearance Zone as the trigger of imminent threat in R2 to address commenter's concerns.
- Adding a sub part to the Transmission Vegetation Management Plan requirement (1.6) in order to address commenter's concerns regarding the elimination of Clearance 1. This change required that the TO account for anticipated conductor movement.
- Creating a second grow-in outage requirement to allow for different VRF levels based on the actual criticality of the line.

There were 3 strong minority views not resolved:

- Some commenters disagreed with the "zero tolerance" nature in the previous version of the standard
- Some commenters disagreed with the proposed minimum Vegetation Inspection frequency of one year.

- Some commenters wanted to retain Clearance 1 from the previous version of the standard.

iv. The Second Posting

The second draft of FAC-003-2 was posted for formal comment from September 10, 2009, to October 24, 2009. A mapping document was again provided to industry to assist in the review of the standard, as well as a new technical reference document. Violation Risk Factors and Violation Severity levels were added to the standard, as well as several other improvements and modifications. Sixty-six sets of comments were received, representing each of the 10 Industry Segments within NERC's stakeholder structure.

v. Transition to Results Based Format

On January 14, 2010, the NERC Standards Committee endorsed the use of Project 2007-07 Vegetation Management as the prototype for the proof-of-concept for using the results-based criteria for developing a Reliability Standard. The results-based initiative is intended to focus the collective effort of NERC and industry participants on improving the clarity and quality of NERC Reliability Standards by developing performance, risk and competency-based requirements that accomplish a reliability objective through a defense-in-depth strategy, while eliminating documentation-driven requirements that do not have an impact on bulk-power system reliability.

The Standards Committee directed the Vegetation Management SDT to stop work refining its second draft of the Vegetation Management standard. Instead, it asked them to inform stakeholders how the team used stakeholder comments to refine the technical requirements carried into the results-based draft of the standard. In response, the drafting team did not develop individual responses to the comments submitted by stakeholders on the second draft of FAC-003-2. Instead, the drafting team produced a summary report that showed all the questions asked and provided a summary indicating how the drafting team used stakeholder comments submitted in response to that question.

vi. The Third Posting

The third draft of FAC-003-2 was posted for informal comment from March 1, 2010 to March 31, 2010. Once again, a mapping document was provided to industry to assist in the review of the standard, as well as a technical reference document. The new standard included an implementation plan, and had been redrafted using the new results-based format. Fifty-five sets of comments were received, representing 8 of the 10 Industry Segments within NERC's stakeholder structure. Based on the comments received, modifications were made to the standard, including:

- Dividing requirement R1 into separate requirements, with separate VRFs
- Removing the phrase "Bulk Power System" from the standard
- Requirement R3 was modified to more explicitly indicate what information needed to be included to be considered a valid procedure, process, or specification.
- Modifying VRFs to align with NERC guidelines.

Some commenters expressed concern regarding the standards use of the Gallet Equation. The drafting team provided an extensive response, explaining its technical justification for the choice. For a detailed discussion of the Gallet Equation and its use, please see Appendix 1 of the Transmission Vegetation Management – FAC-003-2 Technical Reference Document included as **Exhibit I**.

Additionally, a large number of comments were received and considered regarding the new "results-based" format of the standard at this time.

vii. The Fourth Posting and Initial Ballot

A fourth draft of FAC-003-2 was posted for formal comment from June 17, 2010 to July 17, 2010. A mapping document and a technical reference document were provided to industry to assist in the review of the standard. Forty-five sets of comments were received, representing 7 of the 10 Industry Segments within NERC's stakeholder structure. An initial ballot of the standard was conducted from July 9, 2010 to July 19, 2010. The ballot achieved a quorum of 86.18%, and an approval of 65.93%. Based on the comments received, modifications were made to the standard, including:

- Redefining the Glossary term for ROW to address Paragraph 734 of FERC Order 693 and the width of ROW to be maintained;
- Redefining the Glossary term for Vegetation Inspection to include identifying hazards to the line inside the ROW;
- Removing Section 4.4 and footnote 2 addressing "force majeure" and addressing the issue in new footnotes 2, 3 and 4;
- Changing "qualified personnel" to "Transmission Owner" in R4;
- Adding the phrase "but no more than 18 months between inspections" in R6;
- Deleting Table 3 from the Guidelines and Technical Basis section.

Additional changes to the standard were made based on recommendations from members of the standard's "Quality Review" team. Quality Review teams are ad-hoc teams that provide focused compliance and legal feedback on standards and associated documents related to wording, enforceability, structure, grammar, and similar subject areas.

viii. The Fifth Posting and Successive Ballot

The fifth draft of FAC-003-2 was posted for formal comment from January 27, 2011 to February 28, 2011. A mapping document and a technical reference document were provided to industry to assist in the review of the standard. Forty-one sets of comments were received, representing 9 of the 10 Industry Segments within NERC's stakeholder structure. A successive ballot of the standard was conducted from February 18, 2011 to February 28, 2011. The ballot achieved a quorum of 79.28%, and an approval of 79.34%. A non-binding poll was conducted for the VRFs and VSLs. Of those who registered to participate, 77% provided an opinion; and 79% of those who provided an opinion indicated support for the VRFs and VSLs that were proposed.

Around the time of the fifth posting and successive ballot, the Standards Committee approved the 2011-2013 Reliability Standards Development Plan, which lowered the priority of this project relative to other work and moved this project into informal development. With this move, NERC resources supporting this project were reassigned to higher-priority projects. The standards drafting team worked independently to respond to comments and finalize the standard. Based on comments received during the comment and ballot, the definition of MVCD was added. A number of clarifications to the standard language were also undertaken during this time.

Additionally, during this period, the chair of the Standards Committee identified some potential concerns with the standard and requested that the team answer several focused questions. The team developed responses to these questions (included in the Project 2007-07 Vegetation Management Consideration of Issues and Directives document included in the Complete Development History attached as **Exhibit G**), as well as several other supporting documents used during the recirculation ballot.

ix. The Sixth Posting and Recirculation Ballot

The sixth and final draft of FAC-003-2 was posted for recirculation ballot from October 4, 2011, to October 13, 2011. An updated mapping document and technical reference document were provided to industry to assist in the review of the standard. Other supporting documents were prepared to further assist in the review, including a document demonstrating the manner in which FERC directives (as well as other issues) were addressed, an analysis of how the VSLs and VRFs complied with NERC and FERC guidelines, an updated implementation plan, and responses to the questions asked by the Chair of the Standards Committee. The ballot achieved a quorum of 87.17%, and an approval of 86.25%.

x. Board of Trustees Approval

The final draft of FAC-003 was presented to NERC's Board of Trustees for approval on November 3, 2011. NERC staff provided a summary of the improvements made to the standard, as well as a summary of minority issues and associated drafting team responses. NERC staff also proposed an alternative set of VSLs for requirements

R1 and R2, because they believed the VSLs proposed by the drafting team did not meet NERC guidelines. The Board of Trustees approved the standard, and the NERC staff recommended VSLs for Requirements R1 and R2 and directed that it be filed with applicable regulatory authorities.

VII. CONCLUSION

Accordingly, the proposed FAC-003-2 Reliability Standard should be approved because it serves the important reliability goal of ensuring that each applicable entity will manage vegetation in accordance with the standard. Additionally, the proposed standard presents three important themes that all help to improve reliability. First, reliability will be improved with implementation of the new standard. Second, enforceability of FAC-003-2, as compared to FAC-003-1, will be improved and cleaner for NERC and the Regional Entities. And third, NERC registered entities will have greater flexibility to address local vegetation management conditions.

For the reasons set forth above, NERC respectfully requests that the Commission:

- approve FAC-003-2 and the associated Violation Risk Factors and Violation Severity Levels included in **Exhibit A,** effective the first day of the first calendar quarter that is twelve months following the effective date of a Final Rule in this docket;
- approve the implementation plan for FAC-003-2 included in **Exhibit B**;
- approve the three definitions included in **Exhibit C** to be added to the NERC Glossary of Terms Used in NERC Reliability Standards effective the first day of the first calendar quarter that is twelve months following the effective date of a Final Rule in this docket:
    - Right-of-Way (ROW)

- Vegetation Inspection
- Minimum Vegetation Clearance Distance (MVCD)

- approve the retirement of FAC-003-1 and the currently effective definitions of "Right-of-Way" and "Vegetation Inspection" effective midnight immediately prior to the first day of the first calendar quarter that is twelve months following the effective date of a Final Rule in this docket.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 21st day of December, 2011.

/s/ Holly A. Hawkins
Holly A. Hawkins
Assistant General Counsel for North American Electric Reliability Corporation

Exhibit A

Reliability Standard FAC-003-2 — Transmission Vegetation Management submitted for Approval

Effective Dates

This standard becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval is required. Where no regulatory approval is required, the standard becomes effective on the first calendar day of the first calendar quarter one year after Board of Trustees adoption.

Requirement	Jurisdiction									
	Alberta	British Columbia	Manitoba	New Brunswick	Newfound-land	Nova Scotia	Ontario	Quebec	Saskatch-ewan	USA
R1 – R7 (All Req.)	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD	TBD

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.

2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.

3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.

4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.

5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

A. Introduction

1. Title: Transmission Vegetation Management

2. Number: FAC-003-2

3. Purpose: To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

4. Applicability

4.1. Functional Entities:

4.1.1 Transmission Owners

4.2. Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities:

4.2.1. Each overhead transmission line operated at 200kV or higher.

4.2.2. Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.

4.2.3. Each overhead transmission line operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

4.2.4. Each overhead transmission line identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

5. Background:

This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

a) Performance-based — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome*?

b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system*?

c) Competency-based — defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system*?

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2

- Competency-based: Requirement 3

- Risk-based: Requirements 4, 5, 6 and 7

R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term "public lands" includes municipal lands, village lands, city lands, and a host of other governmental entities.

This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

B. Requirements and Measures

R1. Each Transmission Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below[2] [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,[3]
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[4]
3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,[4]
4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage.[4]

M1. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. Each Transmission Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[2] [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage,[3]
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,[4]
3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,[4]

[2] This requirement does not apply to circumstances that are beyond the control of a Transmission Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

[3] If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

[4] Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

4. An encroachment due to vegetation growth into the line MVCD that caused a vegetation-related Sustained Outage[4]

M2. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)

R3. Each Transmission Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following:

3.1 Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

3.2 Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

[*Violation Risk Factor: Lower*] [*Time Horizon: Long Term Planning*]:

M3. The maintenance strategies or procedures or processes or specifications provided demonstrate that the Transmission Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

R4. Each Transmission Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the Transmission Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time*].

M4. Each Transmission Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When a Transmission Owner is constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the Transmission Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M5. Each Transmission Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. Each Transmission Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW[5] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

M6. Each Transmission Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each Transmission Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of a Transmission Owner[6]
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

[5] When the Transmission Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO is granted a time extension that is equivalent to the duration of the time the TO was prevented from performing the Vegetation Inspection.

[6] Circumstances that are beyond the control of a Transmission Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or an applicable regulatory body.

M7. Each Transmission Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

C. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

1.2 Regional Entity Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaint

Periodic Data Submittal

1.4 Additional Compliance Information

Periodic Data Submittal: The Transmission Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the Transmission Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element

of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by Transmission Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High	N/A	N/A	The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.	The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: • A fall-in from inside the active transmission line ROW • Blowing together of applicable lines and vegetation located inside the active transmission line ROW • A grow-in
R2	Real-time	Medium	N/A	N/A	The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.	The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: • A fall-in from inside the

						active transmission line ROW • Blowing together of applicable lines and vegetation located inside the active transmission line ROW • A grow-in
R3	Long-Term Planning	Lower	N/A	The Transmission Owner has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the Transmission Owner's applicable lines. (Requirement R3, Part 3.2)	The Transmission Owner has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the Transmission Owner's applicable lines. Requirement R3, Part 3.1)	The Transmission Owner does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the Transmission Owner's applicable lines.
R4	Real-time	Medium	N/A	N/A	The Transmission Owner experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The Transmission Owner experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5	Operations Planning	Medium	N/A	N/A	N/A	The Transmission Owner did not take corrective action when it was constrained from performing planned vegetation work where an applicable line

						was put at potential risk.
R6	Operations Planning	Medium	The Transmission Owner failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The Transmission Owner failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The Transmission Owner failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The Transmission Owner failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7	Operations Planning	Medium	The Transmission Owner failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The Transmission Owner failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The Transmission Owner failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The Transmission Owner failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Differences

None.

E. Interpretations

None.

F. Associated Documents

Guideline and Technical Basis (attached).

Guideline and Technical Basis

Enforcement:

The Requirements within a Reliability Standard govern and will be enforced. The Requirements within a Reliability Standard define what an entity must do to be compliant and binds an entity to certain obligations of performance under Section 215 of the Federal Power Act. Compliance will in all cases be measured by determining whether a party met or failed to meet the Reliability Standard Requirement given the specific facts and circumstances of its use, ownership or operation of the bulk power system.

Measures provide guidance on assessing non-compliance with the Requirements. Measures are the evidence that could be presented to demonstrate compliance with a Reliability Standard Requirement and are not intended to contain the quantitative metrics for determining satisfactory performance nor to limit how an entity may demonstrate compliance if valid alternatives to demonstrating compliance are available in a specific case. A Reliability Standard may be enforced in the absence of specified Measures.

Entities must comply with the “Compliance” section in its entirety, including the Administrative Procedure that sets forth, among other things, reporting requirements.

The “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” are provided for informational purposes. They are designed to convey guidance from NERC’s various activities. The “Guideline and Technical Basis” section and text boxes with “Examples” and “Rationale” are not intended to establish new Requirements under NERC’s Reliability Standards or to modify the Requirements in any existing NERC Reliability Standard. Implementation of the “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” is not a substitute for compliance with Requirements in NERC’s Reliability Standards.”

Effective dates:

The first two sentences of the Effective Dates section is standard language used in most NERC standards to cover the general effective date and is sufficient to cover the vast majority of situations. Five special cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the standard.

Case 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the Transmission Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.

Date that Planning Study is completed	PY the line will become an IROL element	Date 1	Date 2	Effective Date The latter of Date 1 or Date 2
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Case 2 is needed because a line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Case 3 is needed because a line operating at 200 kV or above that once was designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.

Case 4 is needed because an existing line that is to be operated at 200 kV or above can be acquired by a Transmission Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the Transmission Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network which will thereafter make the line subject to the standard.

Case 5 is needed because an existing line that is operated below 200 kV can be acquired by a Transmission Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the Transmission owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network. In this special case the line upon acquisition was designated as an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC Transfer Path.

Defined Terms:

Explanation for revising the definition of ROW:
The current NERC glossary definition of Right of Way has been modified to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of “right of way” in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the revised definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

Explanation for revising the definition of Vegetation Inspections:
The current glossary definition of this NERC term is being modified to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

Explanation of the definition of the MVCD:

The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 below provides MVCD values for various voltages and altitudes. Details of the equations and an example calculation are provided in Appendix 1 of the Technical Reference Document.

Guidelines:

Requirements R1 and R2:
R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each Transmission Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element of an IROL or Major WECC Transfer Path. R2 is applicable to all other lines that are not elements of IROLs, and not elements of Major WECC Transfer Paths.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations as described more fully in the Technical Reference document.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by a Transmission Operator or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line’s Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of a Transmission Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with a Transmission Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

If the Transmission Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the TO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

Requirement R3:

R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, a Transmission Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the Transmission Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the Transmission

Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the Transmission Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach a Transmission Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the Transmission Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below. In the Technical Reference document more figures and explanations of conductor dynamics are provided.

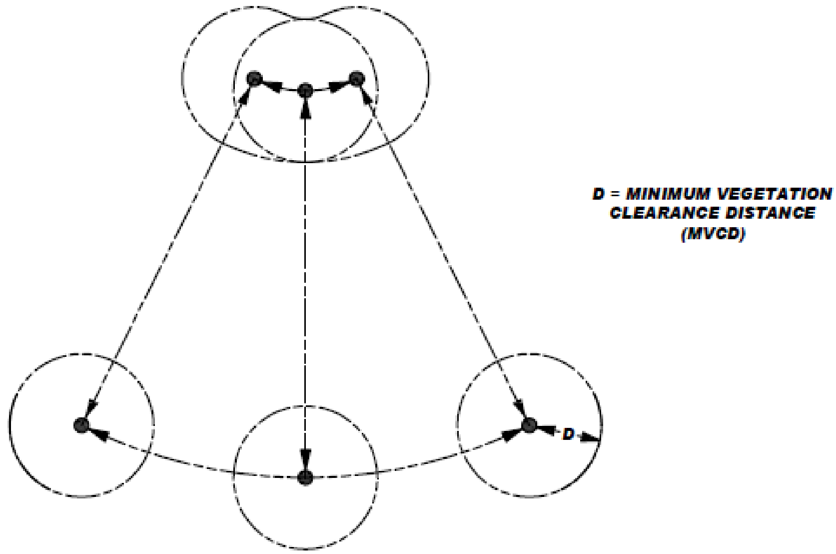

Figure 1

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

Requirement R4:

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the Transmission Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of a Transmission Owner's employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The Transmission Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some Transmission Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5:

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the Transmission Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the Transmission Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the Transmission Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the Transmission Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the Transmission Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the Transmission Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the Transmission Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The Transmission Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:
R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the Transmission Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the Transmission Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when a Transmission Owner operates 2,000 miles of applicable transmission lines this Transmission Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

Requirement R7:
R7 is a risk-based requirement. The Transmission Owner is required to complete its an annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a “span-by-span”, or even a “line-by-line” detailed description of all work to be performed. It is only intended to require that the Transmission Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.
For example, when a Transmission Owner identifies 1,000 miles of applicable transmission lines to be completed in the Transmission Owner’s annual plan, the Transmission Owner will be responsible completing those identified miles. If a Transmission Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be: 1000 – 100 (deferred miles) = 900 modified annual plan, or 900 / 900 = 100% completed annual miles. If a Transmission Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: 1000 – 875 = 125 miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the Transmission Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the Transmission Owner’s system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the Transmission Owner’s easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the Transmission Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Transmission Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the Transmission Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[7]
For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)	(AC) Maximum System Voltage (kV)[8]	MVCD (feet) Over sea level up to 500 ft	MVCD (feet) Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft
765	800	8.2ft	8.33ft	8.61ft	8.89ft	9.17ft	9.45ft	9.73ft	10.01ft	10.29ft	10.57ft	10.85ft	11.13ft
500	550	5.15ft	5.25ft	5.45ft	5.66ft	5.86ft	6.07ft	6.28ft	6.49ft	6.7ft	6.92ft	7.13ft	7.35ft
345	362	3.19ft	3.26ft	3.39ft	3.53ft	3.67ft	3.82ft	3.97ft	4.12ft	4.27ft	4.43ft	4.58ft	4.74ft
287	302	3.88ft	3.96ft	4.12ft	4.29ft	4.45ft	4.62ft	4.79ft	4.97ft	5.14ft	5.32ft	5.50ft	5.68ft
230	242	3.03ft	3.09ft	3.22ft	3.36ft	3.49ft	3.63ft	3.78ft	3.92ft	4.07ft	4.22ft	4.37ft	4.53ft
161*	169	2.05ft	2.09ft	2.19ft	2.28ft	2.38ft	2.48ft	2.58ft	2.69ft	2.8ft	2.91ft	3.03ft	3.14ft
138*	145	1.74ft	1.78ft	1.86ft	1.94ft	2.03ft	2.12ft	2.21ft	2.3ft	2.4ft	2.49ft	2.59ft	2.7ft
115*	121	1.44ft	1.47ft	1.54ft	1.61ft	1.68ft	1.75ft	1.83ft	1.91ft	1.99ft	2.07ft	2.16ft	2.25ft
88*	100	1.18ft	1.21ft	1.26ft	1.32ft	1.38ft	1.44ft	1.5ft	1.57ft	1.64ft	1.71ft	1.78ft	1.86ft
69*	72	0.84ft	0.86ft	0.90ft	0.94ft	0.99ft	1.03ft	1.08ft	1.13ft	1.18ft	1.23ft	1.28ft	1.34ft

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

[7] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[8] Where applicable lines are operated at nominal voltages other than those listed, The Transmission Owner should use the maximum system voltage to determine the appropriate clearance for that line.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[7]
For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)	(AC) Maximum System Voltage (kV)[8]	MVCD meters Over sea level up to 152.4 m	MVCD meters Over 152.4 m up to 304.8 m	MVCD meters Over 304.8 m up to 609.6m	MVCD meters Over 609.6m up to 914.4m	MVCD meters Over 914.4m up to 1219.2m	MVCD meters Over 1219.2m up to 1524m	MVCD meters Over 1524 m up to 1828.8 m	MVCD meters Over 1828.8m up to 2133.6m	MVCD meters Over 2133.6m up to 2438.4m	MVCD meters Over 2438.4m up to 2743.2m	MVCD meters Over 2743.2m up to 3048m	MVCD meters Over 3048m up to 3352.8m
765	800	2.49m	2.54m	2.62m	2.71m	2.80m	2.88m	2.97m	3.05m	3.14m	3.22m	3.31m	3.39m
500	550	1.57m	1.6m	1.66m	1.73m	1.79m	1.85m	1.91m	1.98m	2.04m	2.11m	2.17m	2.24m
345	362	0.97m	0.99m	1.03m	1.08m	1.12m	1.16m	1.21m	1.26m	1.30m	1.35m	1.40m	1.44m
287	302	1.18m	0.88m	1.26m	1.31m	1.36m	1.41m	1.46m	1.51m	1.57m	1.62m	1.68m	1.73m
230	242	0.92m	0.94m	0.98m	1.02m	1.06m	1.11m	1.15m	1.19m	1.24m	1.29m	1.33m	1.38m
161*	169	0.62m	0.64m	0.67m	0.69m	0.73m	0.76m	0.79m	0.82m	0.85m	0.89m	0.92m	0.96m
138*	145	0.53m	0.54m	0.57m	0.59m	0.62m	0.65m	0.67m	0.70m	0.73m	0.76m	0.79m	0.82m
115*	121	0.44m	0.45m	0.47m	0.49m	0.51m	0.53m	0.56m	0.58m	0.61m	0.63m	0.66m	0.69m
88*	100	0.36m	0.37m	0.38m	0.40m	0.42m	0.44m	0.46m	0.48m	0.50m	0.52m	0.54m	0.57m
69*	72	0.26m	0.26m	0.27m	0.29m	0.30m	0.31m	0.33m	0.34m	0.36m	0.37m	0.39m	0.41m

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[7]
For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)
	Over sea level up to 500 ft	Over 500 ft up to 1000 ft	Over 1000 ft up to 2000 ft	Over 2000 ft up to 3000 ft	Over 3000 ft up to 4000 ft	Over 4000 ft up to 5000 ft	Over 5000 ft up to 6000 ft	Over 6000 ft up to 7000 ft	Over 7000 ft up to 8000 ft	Over 8000 ft up to 9000 ft	Over 9000 ft up to 10000 ft	Over 10000 ft up to 11000 ft
	(Over sea level up to 152.4 m)	(Over 152.4 m up to 304.8 m	(Over 304.8 m up to 609.6m)	(Over 609.6m up to 914.4m	(Over 914.4m up to 1219.2m	(Over 1219.2m up to 1524m	(Over 1524 m up to 1828.8 m)	(Over 1828.8m up to 2133.6m)	(Over 2133.6m up to 2438.4m)	(Over 2438.4m up to 2743.2m)	(Over 2743.2m up to 3048m)	(Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient overvoltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.
The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

Comparison of spark-over distances computed using Gallet wet equations vs. IEEE 516-2003 MAID distances

(AC) Nom System Voltage (kV)	(AC) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 7 (Table D.5 for feet) IEEE 516-2003 MAID (ft) @ Alt. 3000 feet
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for Applicability (section 4.2.4):
The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) NERC has a project in place to address at a later date the applicability of this standard to Generation Owners. 4) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

Rationale for R1 and R2:
Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a Transmission Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.

2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.

3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.

4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

Rationale for R3:
The documentation provides a basis for evaluating the competency of the Transmission Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the Transmission Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. See Figure 1 for an illustration of possible conductor locations.

Rationale for R4:
This is to ensure expeditious communication between the Transmission Owner and the control center when a critical situation is confirmed.

Rationale for R5:
Legal actions and other events may occur which result in constraints that prevent the Transmission Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the Transmission Owner to put interim measures in place, rather than do nothing.
The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

Rationale for R6:
Inspections are used by Transmission Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

Rationale for R7:
This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

Version History

Version	Date	Action	Change Tracking
1	TBA	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	01/20/06
1	April 4, 2007	Regulatory Approval - Effective Date	New
2	November 3, 2011	Adopted by the NERC Board of Trustees	

Exhibit B

Implementation Plan for Reliability Standard FAC-003-2 — Transmission Vegetation Management submitted for Approval

Implementation Plan

FAC-003-2

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

FAC-003-2 – Vegetation Management

Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards. There are two revised definitions in the proposed standard. FAC-003-1 will be retired when FAC-003-2 becomes effective.

Compliance with Standard

The standard applies to Transmission Owners.

Effective Date

The effective date is the date entities are expected to meet the performance identified in this standard. The effective date allows entities time to make revisions to their existing transmission vegetation management programs to comply with the new requirements.

This standard becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval is required. Where no regulatory approval is required, the standard becomes effective on the first calendar day of the first calendar quarter one year after Board of Trustees adoption.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC transfer Path.
2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.

3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.
4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard, becomes subject to this standard 12 months after the acquisition date.
5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

Exhibit C

Proposed Terms to be Added to the NERC Glossary of Terms Used in NERC Reliability Standards

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Right-of-Way (ROW)

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.

> *The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.*

Vegetation Inspection

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

> *The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.*
>
> *Current definition of Vegetation Inspection: The systematic examination of a transmission corridor to document vegetation conditions.*

Minimum Vegetation Clearance Distance (MVCD)

The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

Exhibit D

FAC-003-1 Mapping to Proposed NERC Reliability Standard FAC-003-2

Standard FAC-003-1	Proposed Standard FAC-003-2 RBS Draft 4	Observations
Definitions of Terms **Right of Way** A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.	**Definitions of Terms Used in Standard** **Right-of-Way (ROW)** The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria. The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.	 This definition is intended to more clearly recognize the establishment of the Right of Way thought documentation.
Vegetation Inspection The systematic examination of a transmission corridor to document vegetation conditions.	**Vegetation Inspection** The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.	This definition is intended to explain the reason for Vegetation Inspections, and to make clear that entities may perform other inspections at the same time as the Vegetation Inspection.

Standard FAC-003-1	Proposed Standard FAC-003-2 RBS Draft 4	Observations
	The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently. Current definition of Vegetation Inspection: The systematic examination of a transmission corridor to document vegetation conditions.	
	Minimum Vegetation Clearance Distance (MVCD) The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.	This definition was added to ensure a consistent understanding of the phrase.
3. Purpose: To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and	**3. Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.	Results based purpose, driven by Needs and Goals. NEED: To maintain a reliable electric transmission system , preventing the risk of those vegetation-related outages that could lead to Cascading. GOAL: To manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW

Standard FAC-003-1	Proposed Standard FAC-003-2 RBS Draft 4	Observations
reporting vegetation related outages of the transmission systems to the respective Regional Reliability Organizations (RRO) and the North American Electric Reliability Council (NERC).		
4. Applicability: **4.1.** Transmission Owner **4.2.** Regional Reliability Organization **4.3.** This Standard shall apply to all transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RRO as critical to the reliability of the electric system in the region.	4.1. Functional Entities: 4.1.1 Transmission Owners 4.2. Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal , state, provincial, public, private, or tribal entities: 4.2.1. Each overhead transmission line operated at 200kV or higher. 4.2.2. Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator. 4.2.3. Each overhead transmission line operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC. 4.2.4. Each overhead transmission line identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.	4.1.1 replaces 4.1. 4.2 has been removed, as the requirements related to the RRO have been addressed in the compliance section of the standard. 4.2 replaces 4.3. This is superior, as it raises the bar on what lines need to be included within the applicability of this standard. To the extent the areas not covered in 4.2.4 need to be addressed, they should do so under another project and possibly in a separate standard, as the requirements for vegetation management performed in these areas by the GO and DP may be somewhat different than those performed by a Transmission Owner.

Standard FAC-003-1	Proposed Standard FAC-003-2 RBS Draft 4	Observations
	Rationale The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) NERC has a project in place to address at a later date the applicability of this standard to Generation Owners. 4) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.	

R1. The Transmission Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the Transmission Owner's objectives, practices, approved procedures, and work specifications**1**.	**R3.** Each Transmission Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that include(s) the following: **Rationale** The documentation provides a basis for evaluating the competency of the Transmission Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the Transmission Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. See Figure 1 for an illustration of possible conductor locations.	R3 replaces R1.
R1.1. The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation	R6. Each Transmission Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18	R6 replaces R1.1. R6 is superior because it requires entities to take action (perform the inspection), rather than just create a schedule.

and any other environmental or operational factors that could impact the relationship of vegetation to the Transmission Owner's transmission lines.	calendar months between inspections on the same ROW.[1] **Rationale** Inspections are used by Transmission Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.	
R1.2. The Transmission Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design	**R3.** Each Transmission Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that include(s)accounts for the following	Requirement R3 and Parts 3.1 and 3.2 replace the concept of "Clearance 1," as discussed in R1.2 and R1.2.1.

[1] When the Transmission Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO is granted a time extension that is equivalent to the duration of the time the TO was prevented from performing the Vegetation Inspection.

loading, and the effects of wind velocities on conductor sway. Specifically, the Transmission Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors. **R1.2.1.** Clearance 1 — The Transmission Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.	**3.1** Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions; **3.2** Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.	

R1.2.2. Clearance 2 — The Transmission Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These Transmission Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap. **R1.2.2.1** Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied. **R1.2.2.2** Where transmission system	**R1.** Each Transmission Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[2] [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]: 1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage **R2.** Each Transmission Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are <u>not</u> either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[2] [*Violation Risk Factor:*	R1 item 1 and R2 item 2 replace Clearance 2 with the Gallet Equations. These are performance based, and superior to the existing standard, as they require the entities to perform an action (manage vegetation) rather than creating a document.

[2] This requirement does not apply to circumstances that are beyond the control of a Transmission Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

[3] If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.	*Medium*] [*Time Horizon: Real-time*]: 1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage[3],	
R1.3. All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner, to perform their duties.		R1.3 is ambiguous (what is “appropriate”) and unenforceable (what if the Transmission Owner defines no qualifications or training), and was not included in the new version of the standard.
R1.4. Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner is restricted from attaining the clearances specified in Requirement 1.2.1.		R5 replaces R1.4. It is superior because it requires the Transmission Owner to take action (take corrective action), rather than to simply develop mitigation measures.
	R5. When a Transmission Owner is constrained from performing vegetation work on applicable transmission lines operating within their Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the Transmission Owner shall take corrective action to ensure continued vegetation management to prevent encroachments	

	Rationale Legal actions and other events may occur which result in constraints that prevent the Transmission Owner from performing planned vegetation maintenance work. In cases where the transmission line is put at potential risk due to constraints, the intent is for the Transmission Owner to put interim measures in place, rather than do nothing. The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.	
R1.5. Each Transmission Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.	**R4.** Each Transmission Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the Transmission Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment. *[VRF – Medium] [Time Horizon – Real-time]*	R4 replaces R1.5. It is superior because it requires the Transmission Owner to take action (notify the control center) rather than document a process.

	Rationale This is to ensure expeditious communication between the Transmission Owner and the control center when a critical situation is confirmed.	
R2. The Transmission Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.	**R7.** Each Transmission Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include • Change in expected growth rate/ environmental factors • Circumstances that are beyond the control of a Transmission Owner[3] • Rescheduling work between growing seasons • Crew or contractor availability/ Mutual assistance agreements	R7 replaces R2. It is superior because it requires entities to takes specific action (complete 100% of its plan) rather than more generic language (implement its plan). Entities that do not have a plan would be unable to meet this requirement, as they would have no evidence to demonstrate compliance.

[3] Circumstances that are beyond the control of a Transmission Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or an applicable regulatory body.

	• Identified unanticipated high priority work • Weather conditions/Accessibility • Permitting delays • Land ownership changes/Change in land use by the landowner • Emerging technologies **Rationale** This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.	
R3. The Transmission Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission Owner to have been caused by vegetation. **R3.1.** Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24-hour period. **R3.2.** The Transmission Owner is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation related	**Periodic Data Submittal:** The Transmission Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the Transmission Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following: o The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained	Moved to compliance section of standard.

outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation). **R3.3.** The outage information provided by the Transmission Owner to the RRO, or the RRO's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner. **R3.4.** An outage shall be categorized as one of the following: **R3.4.1.** Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW; **R3.4.2.** Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW; **R3.4.3.** Category 3 — Fall-ins: Outages caused by vegetation falling into lines from	Outage; other pertinent comments; and any countermeasures taken by the Transmission Owner. A Sustained Outage is to be categorized as one of the following: o Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW; o Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW; o Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW; o Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW; o Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW; o Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW. o Category 4B — Blowing together: Sustained	

outside the ROW. **R4.** The RRO shall report the outage information provided to it by Transmission Owner's, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the RRO as a result of any of the reported outages.	Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW. The Regional Entity will report the outage information provided by Transmission Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.	
	R1. Each Transmission Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below[2]: 1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage[3] , 2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage[4] , 3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[4], 4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage[4].	New requirement.

	Rationale Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2. Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a Transmission Owner's vegetation maintenance program: 1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program. 2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program. 3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program. 4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple	
	R2. Each Transmission Owner shall manage	New requirement.

	vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[2] [Violation Risk Factor: Medium] [Time Horizon: Real-time]: 1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage[3], 2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage[4], 3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[4], 4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage[4]	

	Rationale Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2. Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a Transmission Owner's vegetation maintenance program: 1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program. 2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program. 3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program. 4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.	

[2] This requirement does not apply to circumstances that are beyond the control of a Transmission Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

[3] If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

[4] Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

Exhibit E

Consideration of Comments Reports Created During the Development of Reliability Standard FAC-003-2 — Transmission Vegetation Management

Project 2007-07
Transmission Vegetation Management

Related Files

Status:
Adopted by the Board of Trustees on November 3, 2011.

Purpose / Industry Need:
FAC-003-1 was approved in 2006. It has some ‘fill-in-the-blank’ components to eliminate. In addition, the following comments submitted by FERC and stakeholders need to be addressed in the refinement of the standard:

FERC Order 693 items
Address the issue regarding applicability:

- Work with the reliability entities and the ERO to collect and make available to the FERC, a list of critical lower voltage transmission lines. (Refer to Applicability 4.3 section of the standard.)
- Consider other criteria in determining applicability of the standard to sub 200kV lines.
- Address the issue of clearances for lines on both federal and non-federal lands:
- Review and analyze outage data (collected by the ERO) then consider defining clearances needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal and non-federal land.
- Consider revising the definition of right of way to encompass required clearance areas.
- Review the suitability of IEEE 516-2003 standard for minimum vegetation clearance.
- Review and analyze outage data (collected by the ERO) then consider defining clearances needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal and non-federal land.
- Consider revising the definition of right of way to encompass required clearance areas.
- Review the suitability of IEEE 516-2003 standard for minimum vegetation clearance.

Procedural items

- Re-format standard to bring it into conformance with the latest version of the Reliability Standard Development Procedure and the ERO Sanctions Guidelines.
- Remove references to RRO in the standard and substitute a responsible entity.
- Add newly developed compliance elements such as time horizons, violation risk factors, violation severity levels, etc.

Stakeholder items

- Prepare technical reference material such as a “white paper” to aid in understanding the technical basis for the standard.
- Review reporting criteria for Category 3 outages in the proposed technical reference material and may remove the reporting requirement of Category 3 outages in R.3 and R.4.
- Consider deleting requirement R.4.
- Review the reporting exemptions to include all category outages under major disasters in Requirement R3.2.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

Draft	Action	Dates	Results	Consideration of Comments
Draft 6 Standard FAC-003-2 Clean | Redline to Last Posting Implementation Plan Clean | Redline **Technical References:** Clean | Redline to Last Posting **Supporting Materials:** FAC-003-1 Mapping Table New and Modified Definitions Consideration of Issues and Directives Violation Risk Factor & Violation Severity Level Assignment Technical, Policy and Regulatory Issues Addressed by SDT	Recirculation Ballot Info>> Vote >>	10/04/11 - 10/13/11 (closed)	Summary>> Full Record>>	
Draft 5 Standard FAC-003-2 FAC-003-2 Clean | Redline to Last Posting Implementation Plan Clean | Redline to Last Posting	Successive Ballot Info>> Vote >>	02/18/11 - 02/28/11	Full Record>> Summary>> Non-binding Results>>	Consideration of Comments **(10)** Consideration of Comments: Non-Binding Poll **(9)**

Supporting Materials: FAC-003-1 Comment Form (Word) **Technical White Paper** Clean | Redline to Last Posting	Comment Period Info>> | Submit Comments>>	01/27/11 - 02/28/11	Comments Received>>	Consideration of Comments **(8)**
Draft 4 Standard – FAC-003-2 FAC-003-2 Clean | Redline to Last Posting Implementation Plan Clean | Redline to Last Posting **Supporting Materials:** Comment Form (Word) Mapping Document Technical White Paper	Initial Ballot Vote>> | Info>>	07/09/10 - 07/19/10 (closed)	Full Record>> Summary>>	Consideration of Comments **(7)**
	Pre-ballot Review Join>> | Info>>	06/17/10 - 07/07/10 (closed)		
	Comment Period Info>> | Submit Comments >>	06/17/10 - 07/17/10 (closed)	Comments Received>>	Consideration of Comments **(6)**
Draft 3 Standard – FAC-003-2 FAC-003-2 Implementation Plan Mapping Document **Supporting Materials:** Comment Form (Word) Technical Reference Document	Informal Comment Period Info>> | Submit Comments>>	03/01/10 - 03/31/10 (closed)	Comments Received>>	Consideration of Comments **(5)**
Draft 2 Standard – FAC-003-2	Comment Period	09/10/09 -	Comments Received>>	Summaries**(4)**

FAC-003-2 Clean | Redline to Last Posting Mapping Document **Supporting Materials:** Comment Form (Word) FAC-003-2 Technical White Paper Implementation Plan	Info>> | Submit Comments>>	10/24/09 (closed)		
Draft 1 Standard – FAC-003-2 FAC-003-2 Mapping Changes **Supporting Materials:** Comment Form (Word)FAC-003-2 – Technical White Paper	Comment Period Info>> | Submit Comments>>	10/27/08 – 11/25/08 (closed)	Comments Received>>	Consideration of Comments **(3)**
Draft SAR Version 3 Vegetation Management Draft SAR Version 2 Draft SAR Version 3 Clean | Redline to 1st Posting	Standard Drafting Team Nomination Submit Nomination>>	07/03/07 - 07/17/07 (closed)		
Draft SAR Version 2 Vegetation Management Draft SAR Version 2 Redline to 1st Posting	Comment Period Info>> | Submit Comments>>	04/10/07 - 05/09/07 (closed)	Comments Received>>	Consideration of Comments **(2)**
	SAR Drafting Team	01/29/07 (closed)		

	Nominations Submit Nomination>>			
Draft SAR Version 1 Vegetation Management Draft SAR Version 1	Comment Period Info>> | Submit Comments>>	01/15/07 - 02/14/07 (closed)	Comments Received>>	Consideration of Comments **(1)**

The Transmission Vegetation Management SAR Drafting Team thanks all commenters who submitted comments on the first draft of the Transmission Vegetation Management SAR. This SAR was posted for a 30 day public comment period from January 15–February 14, 2007. The Standards Committee asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 19 sets of comments, including comments from more than 80 different people from more than 63 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the drafting team revised the SAR to reflect these comments and improvements identified by the FERC in its Mandatory Reliability Standards for the Bulk Power System Order 693.

The following major changes were made to the SAR:

- Updated the Purpose to use language that matches the associated standard (e.g., where FAC-003 is only related to the transmission system, the term, 'bulk power system' was replaced with 'transmission system').
- Added the items NERC is required to address in compliance with FERC Order 693
- Added the following items to the list of items to review in refining the standard:
    - Review reporting criteria for Category 3 outages in the proposed technical reference material and may remove the reporting requirement of Category 3 outages in R.3 and R.4.
    - Consider deleting requirement R.4.
    - Review the reporting exemptions to include all category outages under major disasters in Requirement R3.2.
- Added a commitment to prepare a technical reference such as a "white paper" to aid in understanding the technical basis for the standard.
- The descriptions of the 'Reliability Functions' on page 3 of the SAR were updated to reflect Version 3 of the Functional Model.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Vegetation-Management_Project_2007-7.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Anita Lee (G2)	AESO		✓								
2.	Jay Farrington (G6)	Alabama Electric Coop	✓									
3.	Randall Gann (G6)	Alabama Power Co.	✓									
4.	William J. Smith	Allegheny Power	✓									
5.	Ken Goldsmith (G3)	ALT										✓
6.	Raymond Wiesehan (G6)	Ameren	✓									
7.	James H. Sorrels, Jr.	American Electric Power	✓				✓	✓				
8.	John Neagle (G6)	Associate Electric Coop	✓									
9.	William T. Rees	Baltimore Gas and Electric	✓									
10.	Brian Bartos	Bandera Electric Coop., Inc.										
11.	Michael D. Johnson	Bonneville Power Administration	✓									
12.	Dave Rudolph (G3)	BPEC										✓
13.	Brent Kingsford (G2)	CAISO		✓								
14.	John R. Kellum, Jr.	CenterPoint Energy Houston Electric, LLP	✓									
15.	Michael Spector	Central Hudson Gas & Electric	✓		✓							
16.	Alan Gale (G1)	City of Tallahassee					✓					
17.	Ed Thompson (G4)	ConEd	✓									
18.	John Loftis	Dominion - Electric Transmission	✓									
19.	Billy George (G6)	Duke Energy Carolinas	✓									
20.	Ralph Hale (G6)	Entergy	✓									
21.	Steve Myers (G2)	ERCOT		✓								
22.	Marc Tunstall (G6)	Fayetteville PWC	✓									
23.	Pedro Modia (G1)	Florida Power and Light Company	✓									
24.	Barbara Jaindl	Florida Power and Light Company	✓									
25.	Greg Keller	Florida Power and Light Company	✓									
26.	John Tamsberg	Florida Power and Light Company	✓									
27.	Marty Mennes	Florida Power and Light Company	✓									
28.	Michael Warr	Florida Power and Light Company	✓									
29.	Eric Senkowicz (G1)	FRCC										✓
30.	Mark Bennett (G1)	Gainesville Regional Utilities					✓					
31.	John West (G6)	Georgia Power Co.	✓									
32.	Jimmy Etheridge (G6)	Georgia Transmission Corporation	✓									
33.	Steve Burns (G6)	Gulf Power Co.	✓									
34.	David Kiguel (G4) (I)	Hydro One Networks, Inc.	✓									
35.	George Juhn	Hydro One Networks, Inc.	✓									
36.	Roger Champagne (G4) (I)	Hydro-Québec TransÉnergie	✓									
37.	Ron Falsetti (G2) (G4) (I)	IESO Ontario		✓								
38.	Bill Shemley (G4)	ISO-NE		✓								

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
39.	Kathleen Goodman (G4) (I)	ISO-NE		✓								
40.	Matt Goldberg (G2)	ISO-NE		✓								
41.	Brian Thumm	ITC Transmission	✓									
42.	Clark Hawkins (G1)	Lee County Electric Cooperative			✓							
43.	Eric Ruskamp (G3)	LES										✓
44.	Don Nelson (G4)	MA Dept. of Tele. and Energy									✓	
45.	Robert Coish (G3) (I)	Manitoba Hydro	✓		✓		✓	✓				
46.	Tom Mielnik (G3)	MEC										✓
47.	Dick Pursley (G3)	Midwest Reliability Organization										✓
48.	Bill Phillips (G2)	MISO		✓								
49.	Terry Bilke (G3)	MISO										✓
50.	Carol Gerou (G3)	MP										✓
51.	Joe Knight (G3)	MRO										✓
52.	Richard Mider	New York State Electric and Gas Corporation	✓									
53.	Herb Schrayshuen (G4)	NGRID	✓									
54.	Murale Gopinathan (G4)	Northeast Utilities	✓									
55.	Brian Hogue (G4)	NPCC										✓
56.	Guy V. Zito (G4)	NPCC										✓
57.	Alan Boesch (G3)	NPPD										✓
58.	Jerad Barnhart (G4)	NSTAR	✓									
59.	Greg Campoli (G4)	NYISO		✓								
60.	Mike Calimano (G2)	NYISO		✓								
61.	Ralph Rufrano (G4)	NYPA	✓									
62.	Todd Gosnell (G3)	OPPD										✓
63.	Tom Bowe (G2)	PJM		✓								
64.	Jack Gardner (G6) (I)	Progress Energy Carolinas	✓									
65.	C. Robert Moseley (G5)	Public Service Commission of SC									✓	
66.	David A. Wright (G5)	Public Service Commission of SC									✓	
67.	Elizabeth B. Fleming (G5)	Public Service Commission of SC									✓	
68.	G. O'Neal Hamilton (G5)	Public Service Commission of SC									✓	
69.	John E. Howard (G5)	Public Service Commission of SC									✓	
70.	Mignon L. Clyburn (G5)	Public Service Commission of SC									✓	
71.	Phil Riley (G5)	Public Service Commission of SC									✓	
72.	Randy Mitchell (G5)	Public Service Commission of SC									✓	
73.	Mike Gentry	Salt River Project	✓									
74.	Jerry Lindler (G6)	SCE&G	✓									
75.	John Wolfmeyer (G6)	SERC Vegetation Management Subcommittee										
76.	Sam Stonerock	Southern California Edison	✓									
77.	Jim Busbin (G7)	Southern Company Transmission	✓									

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
78.	JT Wood (G7)	Southern Company Transmission	✓									
79.	Marc Butts (G7)	Southern Company Transmission	✓									
80.	Roman Carter	Southern Company Transmission	✓									
81.	Charles Yeung (G2)	SPP		✓								
82.	Richard Dearman (G6) (I)	TVA	✓									
83.	Jim Haigh (G3)	WAPA										✓
84.	Neal Balu (G3)	WPSR										✓
85.	Pam Oreschnick (G3)	XEL										✓

G1 – FRCC

G2 - ISO/RTO Council Standards Review Committee

G3 - Midwest Reliability Organization

G4 - NPCC CP9 - Reliability Standards Working Group

G5 – Public Service Commission of South Carolina

G6 - SERC Vegetation Management Subcommittee

G7 – Southern Company Transmission

I – Individual comments were submitted in addition to comments as part of a group

Index to Questions, Comments, and Responses

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

Summary Consideration: Most commenters indicated that they do not believe there is a reliability need to revise the technical aspects of this standard. The SAR Drafting Team agrees with commenters who indicated that the original was SAR vague, and the drafting team modified the SAR to clarify that the proposed changes to this standard will address procedural updates to bring the standard into conformance with the latest version of NERC's Reliability Standards Development Procedure and the Sanctions Guidelines in the ERO Rules of Procedure, and will also address the issues raised in the FERC's March 16, 2007 Order 693 - Mandatory Reliability Standards for the Bulk Power System.

<table>
<tr><th colspan="4">Question #1</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td>Bonneville Power Administration</td><td></td><td>☑</td><td>Ok, Yes and No. The first FERC NOPR bullet needs to be addressed. The second bullet is clearly discribed in the standard. A. 4.4.3. The reader must read the statement in context. It meets the Standard Review Guidelines.</td></tr>
<tr><td colspan="4">Response:
The FERC is no longer indicating a need to develop a requirement for a minimum inspection cycle (March 16, 2007 Order 693) and stakeholders indicated they did not support this change, so it was removed from the SAR.
The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to <200kV is necessary.
The Drafting Team does not agree that the Standard Review Guidelines have been met. For example the guidelines calls for 'time horizons' to be assigned to each requirement, and the standard currently does not have these. The standard also needs to replace its 'levels of non-compliance' with 'violation severity levels' to support the latest version of the Sanctions Guidelines.</td></tr>
<tr><td>Bandera Electric Coop.</td><td></td><td>☑</td><td>The items listed as potential revisions are vague and do not provide sufficient justification to alter the current requirements of this standard which has been in effect less than 1 year. The current standard allows for the region to determine which transmission lines are critical to reliability and should be included in a Transmission Owner's Transmission Vegetation Management Plan regardless of voltage classification. The current standard also allows each TO the flexibility to develop its plan in accordance with its specific geography and operating environment. There is no need to be more prescriptive.</td></tr>
<tr><td colspan="4">Response:
The Drafting Team agrees that the first SAR draft was vague. The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes:
Re-format FAC-003-1 to conform to current Standards Development Procedure.
Remove references to RRO in the standard and substitute a responsible entity.
Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels.
The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to <200kV is necessary.
The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability</td></tr>
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Question #1			
Commenter	**Yes**	**No**	**Comment**
Standards for the Bulk Power System.			
ITC Transmission		☑	While there may be "statutory" needs to address (e.g., FERC's request to modify particular components of the existing Standard), we do not feel there is a reliability need to do so.
Response: ▪ The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes: o Re-format FAC-003-1 to conform to the current Standards Development Procedure. o Remove references to RRO in the standard and substitute a responsible entity. o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels. ▪ The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.			
Hydro One Networks, Inc.		☑	We believe that at this time it is premature to move forward with changes to the standard that are based on voltage class issues. The Standard, as developed, applies to the BES which have been determined by a performance based methodology. NERC should wait until the BES vs. BPS issue is resolved.
Response: ▪ The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes: o Re-format FAC-003-1 to conform to the current Standards Development Procedure. o Remove references to RRO in the standard and substitute a responsible entity. o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels.			
Hydro-Québec TransÉnergie		☑	We believe that it is premature to move forward with changes based on voltage class. Applicability of the standard should only be to those portions of the system that are part of the Bulk Power System which have been determined by a performance based methodology.
Response: ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to <200kV is necessary.			
Northeast Power Coordinating Council		☑	NPCC participating members believe that it is premature to move forward with changes based on voltage class. Applicability of the standard should only be to those portions of the system that are part of the Bulk Power System which have been determined by a performance based methodology.
Response: ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to <200kV is necessary.			
American Electric Power		☑	American Electric Power believes that the current standard (when thoroughly read and understood) is completely adequate to maintain a reliable transmission system with minimum risk of vegetation-related outages.

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Remove references to RRO in the standard and substitute a responsible entity.
Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels.
The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.</td></tr>
<tr><td>New York State Electric and Gas Corporation</td><td></td><td>☑</td><td>The current draft FAC 003 1 will provide a high level of reliability for the transmission bulk delivery system which the public now expects. After a comprehensive industry review which included industry balloting, the current Vegetation Management Standard 003 1 was approved in Feburary 2006 and several sections did not go in to effect for one year (2007). Sufficient time should be allowed so that impact of the current standard can be monitored.

FAC 003 1 was designed to prevent cascading type outages and by establishing a standard for 200KV lines and above catastrophic type power outages will be eliminated. Lower volatge lines can be placed under this standard when the impact on the bulk delivery system requires tighter management as determined by local reliability organizations. Inspection cycles must be designed to meet regional needs based on local conditons, and the current standard provides this flexiblity.</td></tr>
<tr><td colspan="4">Response:
The Drafting Team believes a revised standard is justified because it needs to include the following NEW procedural changes:
Re-format FAC-003-1 to conform to the current Standards Development Procedure.
Remove references to RRO in the standard and substitute a responsible entity.
Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels.
The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to <200kV is necessary.
The FERC is no longer indicating a need to develop a requirement for a minimum inspection cycle (March 16, 2007 Order 693) and stakeholders indicated they did not support this change, so it was removed from the SAR.
The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.</td></tr>
<tr><td>SERC Reliability Corporation</td><td>☑</td><td>☑</td><td>The SERC VMS is unsure how to answer the question as it is worded, but has the following comments on the SAR:

The current standard contains appropriate requirements and measures to ensure the owners vegetation management program is implemented and managed to ensure the reliability of the transmission system. Mandating inspection cycle</td></tr>
</table>

Question #1			
Commenter	**Yes**	**No**	**Comment**
			frequencies will not enhance nor ensure reliability by inspecting more or less frequently. The minimum vegetation clearances at maximum operating conditions that are established within the owner's program, which is auditable by the ERO, will ensure reliability. Extending the requirements to lines other than those >200KV may reduce the focus on those lines and may cause the allocation of resources away from lines >200KV. Generally easements are narrower on lower voltage lines, requiring more resources and emphasis on these lines. This may have an effect on the ability to focus clearing efforts on those lines that will have a much greater impact on the bulk power system. The IEEE standard when used as the minimum clearance distance at maximum operating condition will ensure reliability when these clearances are maintained by vegetation management activities. In addition, we do not agree that a standard of zero tolerance for vegetaion-related outages in the ROW is weak on compliance.
Response: ▪ The FERC is no longer indicating a need to develop a requirement for a minimum inspection cycle (March 16, 2007 Order 693) and stakeholders indicated they did not support this change, so it was removed from the SAR. ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary. ▪ The Drafting Team agrees with the commenter and recognizes that the IEEE standard is applicable. ▪ The Drafting Team modified the SAR to eliminate the comment that the standard is weak on compliance as this comment was satisfied when Version 1 of the standard was developed. ▪ The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.			
Progress Energy		☑	The current standard contains appropriate levels of guidelines and penalties to ensure the owners vegetation management program is implemented and managed to ensure the reliability of the transmission system. Mandating inspection cycle frequencies will not enhance nor ensure reliability by inspecting more or less frequently. The minimum vegetation clearances at maximum operating conditions that are established within the owner's program that are auditable by the ERO will ensure reliability. By adding lines other than those >200KV may reduce the focus on those lines and impact the budget dollars allocated to focus on the lines >200KV. Generally easements are much more narrow on lower voltage lines, the impact on budget dollars would often require more emphasis on these lines. This may have an effect on the ability to focus clearing efforts on those lines that will have a much greater impact on the bulk power system. The IEEE standard when used as the minimum clearance distance at maximum operating condition will ensure reliability when these clearances are maintained by vegetation management activities.

Question #1			
Commenter	**Yes**	**No**	**Comment**
Response: ▪ The current version of the standard does not include 'time horizons' and uses 'levels of non-compliance' rather than 'violation severity levels' - 'time horizons' and 'violation severity levels' are needed to conform to the latest version of the Sanctions Guidelines included in the ERO Rules of Procedure. ▪ The FERC is no longer indicating a need to develop a requirement for a minimum inspection cycle (March 16, 2007 Order 693) and stakeholders indicated they did not support this change, so it was removed from the SAR. ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary. ▪ The Drafting Team agrees with the commenter and recognizes that the IEEE standard is applicable. ▪ The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.			
CenterPoint Energy Houston Electric, LLP		☑	CenterPoint Energy disagrees that there is a reliability-related need to address the proposed revisions to FAC-003-1. This SAR proposes to establish a minimum vegetation inspection cycle for transmission facilities throughout the United States. Yet, based upon the location of each utility, different vegetation and growth rates will be experienced throughout the country. Placing a time specific vegetation management cycle for all regions does not address the wide divergence of vegetation and growth rates that each utility must face. For instance, in certain areas of the country, such as desert areas, vegetation growth rates are exceedingly small; therefore, vegetation management cycles would likely be for extended periods of time. Placing a required frequent cycle will unnecessarily increase the costs to ratepayers. While in other parts of the country, vegetation can grow rapidly, and there should be shorter periods of time for the vegetation management cycle. Based upon these facts, CenterPoint Energy does not believe that adopting a standard inspection cycle that is applicable to all regions is prudent. However, CenterPoint Energy understands and supports the concept of standard requirements applicable to all regions where such standardization is practical and reasonable. In the specific case of vegetation management, it may be reasonable and practical to establish a national standard based on maximum number of allowed annual vegetation-caused outages per 100-circuit-miles of transmission. Such a standard would allow utilities flexibility to use inspection cycles and other practices that are prudent based on each utility's circumstances while still holding utilities accountable for the results.

Question #1			
Commenter	**Yes**	**No**	**Comment**
			The SAR also proposes to change the 200 kV threshold and use of the IEEE standard for minimum clearances. These requirements were established by a broad consensus of industry experts. CenterPoint Energy believes the broad industry consensus on these matters should be respected. CenterPoint Energy submits the following specific comments: Minimum inspection cycle, FERC NOPR Paragraph 382- CenterPoint Energy disagrees that "complete discretion left to the transmission owners in determining inspection cycles limits the effectiveness of the Reliability Standard." The standard is effective because it requires the transmission owners to balance several factors to achieve the optimum inspection cycle. It is not necessary to specify a specific inspection interval in the standard. The inspection cycle interval is one component of several conditions to be considered in FAC-003-1 Requirement R1.2.1 for establishing the required Clearance 1 of the NERC standard. Other conditions that should be considered include operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. It is the growth rate of the vegetation coupled with the amount of clearance achieved at the time of maintenance that determines the inspection cycle interval. As such, the longer the inspection interval, the larger the clearance that must attained to achieve balance. If the utility does not achieve balance, then it will likely not avoid vegetation-related outages. It would not be necessary for a utility to be faulted based on its inspection interval, rather it would be measured for compliance under FAC-003-1 D2.3.1, D2.3.2, D2.3.3, and D2.4.1 for operational conditions regarding maintaining the minimum clearance (Clearance 2) required under FAC-003-1 Requirement R1.2.2 and any actual vegetation-related outages. FERC NOPR Paragraph 383-

Question #1			
Commenter	**Yes**	**No**	**Comment**
			CenterPoint Energy disagrees that "a one-year vegetation inspection cycle is the "norm" for the industry." The reference to "76 of 161 entities surveyed conduct ground inspections once a year" was taken from Table 3 entitled "Ground Inspection Frequency". The table can also be interpreted to indicate that 78 of 161 entities surveyed conduct ground inspections on cycles other than once a year. At best, the table shows a distribution of the varying practices of companies surveyed. The table by itself does not indicate the level of reliability provided by each of those companies. The table entries may also be incomplete because the original order under Docket EL04-52-000 under paragraph 12c asked "how often the transmission provider inspects that facility for vegetation management purposes" which did not specify ground or aerial inspection. The EEI template that many respondents used did specify ground inspection and aerial inspection separately, but the template was not used by all of the respondents as noted in the report. Interpolation of the data collected may have affected the accuracy of the results reported, so specific conclusions should consider the disparity between how the data request was worded and how the data was reported. It is important to clearly distinguish between ground inspection, aerial inspection, and pruning cycle when soliciting and interpreting industry data. Additionally, new technologies such as airborne laser surveys are coming to the market which may replace or augment other types of vegetation inspections as they become cost-effective. The industry "norm" may change as a result. FERC NOPR Paragraph 384- Although CenterPoint Energy does not agree with establishing a "one year minimum inspection cycle", it should be left to the discretion of the transmission owner as to what type of inspection is employed so that the most cost-effective methods can be utilized, depending on the system's size and terrain. It should also be made clear that "inspection cycle" is not intended to mean "pruning cycle". Remove 200kV threshold, FERC NOPR Paragraph 385- CenterPoint Energy believes the applicability of FAC-003-1 should be "to all transmission lines operated at 200kV and above and to any lower voltage lines

Question #1			
Commenter	**Yes**	**No**	**Comment**
			designated by the regional reliability organization as critical to reliability", because such a standard most closely matches the vegetation management reporting requirements from Docket EL04-52-000. Voltages below this threshold are not likely to impact the reliability of the Bulk Power System. Further, regional reliability organizations have the authority to designate lower voltages critical to reliability as appropriate. The proposed change is unnecessary. IEEE Standard as basis for minimum clearance to prevent flashover (Clearance 2) - CenterPoint Energy believes that the IEEE standard is sufficient and appropriate as a basis to determine the specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions (Clearance 2). Clearance 2 also must consider additional clearance for the dynamic movement of the transmission conductors to avoid vegetation related outages. Thus, the minimum clearances that a transmission owner must identify and document depend on a variety of conditions including, but not limited to, transmisison line voltage, temperature, wind velocities, and altitude.

Response:

- The FERC is no longer indicating a need to develop a requirement for a minimum inspection cycle (March 16, 2007 Order 693) and stakeholders indicated they did not support this change, so it was removed from the SAR.
- The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary.
- The Drafting Team agrees with the commenter and recognizes that the IEEE standard is applicable.

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<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td>Central Hudson Gas & Electric</td><td></td><td>☑</td><td>The proposed revisions listed under the FERC NOPR do not provide proper justification to alter the requirements in the current FAC-003-1 document that was adopted one year ago.

First, "a minimum vegetation inspection cycle that allows variation in physical difference" is already called for under the current standard. As stated in Section R1.1. of FAC-003-1, a schedule already should be defined under the transmission vegetation management program (TVMP). This schedule already allows for "variation in physical difference" since the current standard states that "this schedule should be flexible enough to adjust for changing conditions."

Secondly, under Applicability Section 4.3., the current standard already allows for lines with lower voltage than 200kV to be "designated by the RRO as critical" and therefore applicable to the standard. Removal of the 200kV benchmark is not needed.

And lastly, under the FERC staff report, the IEEE standard provides guidance in clearances and has been the industry standard for many years. If FERC objects to using this standard then they should provide clearances that can be discussed and agreed upon by the transmission owners.</td></tr>
<tr><td colspan="4">Response:
▪ The FERC is no indicating a need to develop a requirement for a minimum inspection cycle (March 16, 2007 Order 693) and stakeholders indicated they did not support this change, so it was removed from the SAR.
▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary.
▪ The Drafting Team agrees with the commenter and recognizes that the IEEE standard is applicable.</td></tr>
<tr><td>Southern California Edison</td><td></td><td>☑</td><td>There was no empirical or anecdotal evidence presented by FERC staff to support the Commission's view that the reliability of the Bulk Power System will be enhanced with further revisions to FAC-003-1. This standard was the subject of vigorous industry debate in a previous SAR. Although it is far from perfect, the proposed revisions will not improve reliability and may very well damage existing VM programs.</td></tr>
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▪ The Drafting Team believes a revised standard is justified because it needs to include the following NEW procedural changes:
o Re-format FAC-003-1 to conform to the current Standards Development Procedure.
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Commenter	**Yes**	**No**	**Comment**
o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels. ▪ The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.			
Baltimore Gas and Electric		☑	The revisions listed in the NOPR and FERC Staff Report do not provide the necessary justification to alter the requirements in the current FAC-003-1 document. The existing requirements already allow for each utility to specify the inspection requirements. There is no need to more prescriptive. The existing requirements already allow for the ERO to designate critical lines less than 200 kV so removal of the 200 kV benchmark is unecessary. The IEEE Standard is worthwhile to keep as a benchmark without which there would be no solid guidance for minimum clearances.
Response: ▪ The Drafting Team believes a revised standard is justified because it needs to include the following NEW procedural changes: o Re-format FAC-003-1 to conform to the current Standards Development Procedure. o Remove references to RRO in the standard and substitute a responsible entity. o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels. ▪ The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System. ▪ The FERC is no indicating a need to develop a requirement for a minimum inspection cycle (March 16, 2007 Order 693) and stakeholders indicated they did not support this change, so it was removed from the SAR. ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary. ▪ The Drafting Team agrees with the commenter and recognizes that the IEEE standard is applicable.			
Southern Company Transmission	☑	☑	We are not sure what you are asking? If you are asking whether we support the standard as it exists today-Southern does! If you are asking whether Southern Co. supports the changes being recommended in this Standard-we DON"T. The present standard appears to be serving its intended purpose and the industry as currently written. The standard should not be revised until it has demonstrated it is ineffective or inadequate for ensuring the reliability of the nation's transmission grid. Any changes to the standard should be based on empirical data rather than the assumption that the Standard is not serving its intended purpose. The standard has not been in effect long enough to determine if it is ineffective.
Response:			

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<tr><td>TVA</td><td>☑</td><td>☑</td><td>As worded this question is confusing however the following comments are presented on the SAR:
The current standard contains appropriate requirements and measures to ensure that vegetation related outages will not cause cascading transmission blackouts. Mandating new explicit inspection cycle frequencies will not enhance nor ensure reliability by inspecting more or less frequently. The current minimum vegetation clearances at maximum operating conditions that are established within the owner's program, which is auditable by the ERO, is sufficient to prevent vegetation related cascading transmission
blackouts. Extending the requirements to a much a larger population of lines would reduce the current focus on the most important lines (those >200 kV). The IEEE standard when used as the minimum vegetation clearance distance at maximum operating condition will ensure desired performance of the lines. A standard of zero tolerance for vegetation related outages in the ROW is not a weak standard on compliance.</td></tr>
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</table>

Question #1			
Commenter	**Yes**	**No**	**Comment**
Florida Power and Light Company	☑		FPL recognizes the need to address the concerns outlined in the NOPR and by the FERC Staff.
Response: ▪ The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes: o Re-format FAC-003-1 to conform to the current Standards Development Procedure. o Remove references to RRO in the standard and substitute a responsible entity. o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity. ▪ The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.			
Public Service Commission of South Carolina	☑		
Manitoba Hydro	☑		
IESO Ontario	☑		
Salt River Project	☑		
ISO New England	☑		
Dominion - Electric Transmission	☑		
Midwest Reliability Organization	☑		
ISO/RTO Council Standards Review Committee	☑		
Allegheny Power	☑		

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

Summary Consideration: Many commenters indicated there is no need to change the applicability of the requirements in this standard. The FERC indicated that the Standard Drafting Team should review and consider whether a change to the applicability to voltage <200kV is necessary.

Furthermore, some commenters expressed support for the IEEE standard's use in the FAC-003-1 Standard while the FERC declines to endorse the use of the IEEE standard as the 'only' minimum clearance. The SAR was revised to indicate that the Standard Drafting Team will seek to clarify the rationale for the use of the IEEE standard in supplemental reference material to be prepared as part of the scope of this SAR.

Question #2			
Commenter	**Yes**	**No**	**Comment**
Bonneville Power Administration	☑		Since this posting is for comment it would have been nice to provide more information as to why the FERC staff objects to the IEEE standard (since it meets the guidelines for as a North America standard. Also, why are stakeholders concerned with Reliability Coordinators vs. RRO?
Response: ▪ The Drafting Team recognizes that the IEEE standard is applicable. The FERC staff has questioned the applicability of the IEEE standard and the Drafting Team agreed to address their questions and concerns. ▪ The Drafting Team believes a revised standard is justified because it needs to include the following NEW procedural changes: o Re-format FAC-003-1 to conform to the current Standards Development Procedure. o Remove references to RRO in the standard and substitute a responsible entity. Making FAC-003 applicable to the RRO is in violation of the legislation that established the ERO. This legislation states that enforceable standards can apply only to owners, users and operators of the bulk power system. o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels.			
Bandera Electric Coop.	☑	☑	As submitted, the SAR appears to completely re-open this standard negating many months of work and industry comment to reach the consensus reflected in the current FAC-003.
Response: ▪ The ERO Rules of Procedure include the latest versions of the Reliability Standards Development Procedure Manual and the Sanctions Guidelines. These documents were approved following the approval of FAC-003-1. FAC-003-1 will need to be revised to bring the standard into conformance with these documents.			
Northeast Power Coordinating Council		☑	See response to question 1, above.
Response: See the drafting team's response to your comments on question 1.			
CenterPoint Energy Houston Electric, LLP		☑	CenterPoint Energy does not agree with the scope of the SAR for the reasons discussed in response to question 1.

Question #2			
Commenter	**Yes**	**No**	**Comment**
Response: See the drafting team's response to your comments on question 1.			
Central Hudson Gas & Electric		☑	See comments above.
Response: See the drafting team's response to your comments on question 1.			
American Electric Power		☑	American Electric Power is not aware of any evidence to support a need for revising the vegetation management standard.
Response: ▪ The ERO Rules of Procedure include the latest versions of the Reliability Standards Development Procedure Manual and the Sanctions Guidelines. These documents were approved following the approval of FAC-003-1. FAC-003-1 will need to be revised to bring the standard into conformance with these documents.			
FRCC		☑	As stated in this SAR comment form, the improvements should be made to bring the standard into conformance with the Reliability Standards Development Procedure which at this time is version 6.0, adopted by NERC BOT, 11/1/2006. The SAR scope via the attached Standard Review Guidelines includes two areas not defined within the procedure. The Mitigation Time Horizons and definitions for the violation severity levels (VSLs), Lower, Moderate, High and Severe. We understand the description of Mitigation Time Horizons and definitions for VSLs are included in the SAR (the concept of Violation Time Horizons is included in the Sanctions Guidelines, appendix 4B, NERC Compliance Filing to FERC dated October 18th, 2006), but these discrepancies are part of a broader policy issue and since their use is not clearly stipulated in the NERC Reliability Standards Development Procedure, including them in the scope of the SAR is premature and will cause unnecessary confusion to stakeholders and regulators. The process is requesting the industry to comment on a scope that is defined outside the reliability standards process and as such is subject to revisions and interpretations outside the process as well. This appears inappropriate and at the extreme will lead to inconsistent understanding, measurement and enforcement of compliance actions. The Mitigation Time Horizons and VSL levels should be defined in the Reliability Standards Development Procedure prior to inclusion in the scope of a SAR. Specific Items Within Current SAR Scope:

Question #2			
Commenter	**Yes**	**No**	**Comment**
			The establishment of minimum inspection cycles has been addressed previously, in the development of the current standard and was found very problematic given the large variety of vegetative conditions throughout North America. The vegetation that was identified as a contributing cause to the 2003 Northeast Blackout had already been identified by previous inspection activities. It was the failure to take action on the known site conditions that contributed to the event. Therefore, a minimum inspection cycle would still NOT have prevented or mitigated the scope of the Blackout. The current 200 kV threshold ensures that vegetation management efforts are focused on the critical bulk power transfer lines and that TVM efforts are not diluted by including additional lower voltage lines. In practicality, the RRO designation process provides the necessary flexibility to the Regions to address localized areas where bulk power system reliability may be compromised by lower voltage vegetation outages. To note as well, Northeast Blackout related vegetation outages which initiated the cascade occurred on lines that operate at 345 kV, well above the current threshold. The FRCC supported the development of Clearance 2, as established in the current standard, as this was a consensus selection by not only the subject matter experts, but many industry participants. Picking the ANSI Z133.1 Table 1 or 2 as the NOPR suggests, could immediately place thousands of miles of transmission lines out of compliance even though operating data indicates that the lines have performed satisfactorily for years. The concern would be, the resulting dilution of valuable industry and regulator resources. The SAR includes the following stakeholder comment: "Too weak on compliance" . We caution that we feel the compliance section does need refining, but that in a world of limited resources should focus on trends in vegetation outages and not necessarily on single outages. For transmission owners, two outages on a radial 230 kV circuit should not carry the same penalty as eight outages on multiple 230 kV circuits within a network. We would recommend that compliance be refined to identify trends, relevance and risk probability to help the industry focus their resources appropriately.

Response:

- The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes:

Question #2			
Commenter	**Yes**	**No**	**Comment**
o Re-format FAC-003-1 to conform to the current Standards Development Procedure. o Remove references to RRO in the standard and substitute a responsible entity. o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels. ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to <200kV is necessary. ▪ The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.			
ITC Transmission		☑	The Standard Drafting Team should not be given lattitude to "include other improvements to the standards deemed appropriate by the drafting team." The purpose of the SAR is to identify the changes contemplated by the need for the Standard Revision. If there are changes that the SAR requestor would like to make to the Standard, they should be spelled out in the SAR. If the SAR requestor does not really know the changes that should be made to the standard, then the SAR should be withdrawn until the need for a SAR can be adequately justified.
Response: ▪ The Drafting Team agrees and has removed the paragraph in the brief description of the SAR that opened the scope to other improvements.			
ISO/RTO Council Standards Review Committee ISO New England		☑	The SRC (ISO-NE) would suggest that the SAR be clear that it will be a complete review of the subject requirements: to include the addition, deletion and modification of requirements as agreed to by public consensus.
Response: ▪ The Drafting Team removed the paragraph in the brief description of the SAR that opened the scope to other improvements. The Drafting Team concurs with consensus of the commenters that the technical elements of this standard are complete. The intent of the SAR modification is to address FERC issues and to conform to updates in the Reliability Standards Development Procedure and Sanctions Guidelines.			
Hydro-Québec TransÉnergie	☑	☑	FERC staff report has objection to use IEEE standard. Should we understand that another standard is recommended instead?
Response: ▪ The Drafting Team recognizes that the IEEE standard is applicable. The FERC staff has questioned the applicability of the IEEE standard and the Drafting Team agreed to address their questions and concerns.			
Hydro One Networks, Inc.		☑	To address FERC's objection to use the IEEE standard, it is necessary to clarify the objective of the Vegetation Management Standard. As we understand it, the focus of the FAC-003-1 standard is system reliability and as such, the responsibility and authority on defining and applying the safety margins is rightly assigned to the transmission owner. We request clarification on how employing safety factors will address reliability and how prescribing minimum clearances within the standard will

Question #2			
Commenter	**Yes**	**No**	**Comment**
			improve reliability. Please note that the Canadian Standards Association is revising standard C22.3 No. 1 - Overhead Systems. The new version will include clearances to vegetation and the proposed minimum clearances are in alignment with FAC-003-1.
Response: ▪ The Drafting Team recognizes that the IEEE standard is applicable. The FERC staff has questioned the applicability of the IEEE standard and the Drafting Team agreed to address their questions and concerns.			
SERC Reliability Corporation Progress Energy	☑	☑	Minimum Inspection Intervals: The SERC VMS (Progress Energy) believes that FAC 003-1 provides the proper amount of flexibility regarding vegetation inspection cycles and that the Standards Drafting Team should not impose minimum inspection intervals on a continent with such regional diversity in climate and plant life. The purpose of Requirement 1.1 of standard FAC-003-1 is to put the responsibility for proper inspection cycles on the entity that knows the local conditions and can best define what that inspection frequency should be, the Transmission Owner. Both NERC and the FERC staff have recognized that various local conditions can have an affect on the determination of adequate inspection frequencies. Establishing a mandatory minimum inspection frequency could have two detrimental effects on the industry. First, where a particular region is heavily forested and has heavy rainfall along with extended or year round growing seasons, a “back stop” minimum inspection frequency could lead transmission owners to conduct inspections less frequently than required by the local conditions. This could result in a Transmission Owner complying with the standard while not adequately protecting the reliability of that region’s transmission system. This is a “lowest common denominator” approach which FERC has repeatedly stated is inappropriate for the reliability standards. Second, where a particular region is arid, sparsely forested or has a minimum growing season, a “back stop” minimum could require a more frequent interval than is realistically needed. This would result in increased and unnecessary costs for electric utility customers without providing an increase in system reliability. In its discussion of inspection intervals, FERC indicates that a “one-year vegetation

Question #2			
Commenter	**Yes**	**No**	**Comment**
			inspection cycle is reasonable." FERC NOPR, 10/20/2002 paragraph 383. The Commission continues by stating "a one-year inspection cycle is the 'norm' for the industry, but not the lowest common denominator…" It follows from this observation that the industry as a whole recognizes and follows appropriate inspection intervals without a need to change the standard. Further, FERC also states "some variation to a continent-wide, one-year minimum inspection cycle should be allowed due to physical differences such as climate and species of vegetation." FERC NOPR 10/20/2006, paragraph 382. FERC's express recognition that a "one size fits all" approach is not appropriate further supports the SERC VMS's contention that the existing inspection requirements in standard FAC-003-1 should remain unchanged. Finally, the performance metrics of FAC-003 require the reporting of applicable transmission interruptions that are caused by vegetation. This process should appropriately identify Transmission Owners' inspection cycles that are not adequate. In this event, the ERO has the authority to engage the Transmission Owner in enforcement compliance actions and, therefore, can remedy any vegetation-related outage that is attributed to the Transmission Owner's inspection frequency. Standard Applicability: The SERC VMS disagrees with the proposal to revise the 200 kV threshold for determining facilities subject to this standard. The majority of transmission facilities below 200 kV have significantly different design/construction/operating characteristics and have not been cited as impacting bulk power system reliability. For example, the Final Report on the August 14, 2003 Blackout in the United states and Canada: Causes and Recommendations April 2004 by the U.S.- Canada Power System Outage Task Force and all referenced major blackouts(pages 103-115) in that report, cited only outages which involved vegetation at line voltages above 200 kV. Generally applying requirements appropriate for 200 kV lines to lines less than 200 kV will result in significant documentation and reporting of items such as restrictions, mitigation plans, off right-of-way vegetation-related outage investigation/information and other issues, all of which dilutes the focus on lines that directly impact bulk power system reliability.

Question #2			
Commenter	**Yes**	**No**	**Comment**
			Revising the standard to use general criteria or broad language for defining "Bulk Power System" transmission lines covered by the standard could become a “one size fits all” approach. If that approach were taken, the standard would cover a significant number of transmission lines that have no direct impact on bulk power system reliability under standard planning/operating conditions, resulting in a significant increase in costs for electric customers without improving “Bulk Power System” system reliability. The SERC VMS believes that the applicability provision of the standard should instead focus attention of the standard only on the transmission lines below 200 kV that directly impact “Bulk Power System” reliability, as the current version requires. In sum, while the SERC VMS (Progress Energy) recognizes some validity in the Commission’s concern, the SERC VMS (Progress Energy) recommends that the applicability provision of this standard should be revised only if existing system design, planning or operating reliability criteria and parameters are considered as a basis for defining the applicability of the standard. To that end, the SERC VMS recommends each Regional Entity (RE) determine applicability of FAC-003 to those lines within the region that are between 100 kV and 200 KV if and only if they are identified as operationally significant elements of Interconnection Reliability Operating Limits (“IROLs”). IEEE Standard for Minimum Clearances: The SERC VMS disagrees with objections in the FERC staff report to the use of the IEEE 516-2003 clearance as the minimum acceptable distances for “Clearance 2”. The IEEE 516-2003 tables are appropriate for defining the minimum acceptable clearances to prevent flashover between conductors and vegetation under all rated electrical operating conditions. Closer minimum clearances such as the minimum length of a support insulator could have been adopted as a “lowest common denominator” clearance. However the clearance in IEEE 516-2003 was adopted to ensure an additional margin of reliability. FERC staff references ANSI Z-133 which is a safety standard that addresses worker safety as well as the safety of the general public. As such, the purpose of ANSI Z-133 is to address worker safety and is not focused on transmission line reliability, which is the purpose of FAC-003-1. OSHA, NESC and other related safety standards have clearances in excess of IEEE 516-2003. Those clearances are clearly focused on safety issues and will still apply

Question #2			
Commenter	**Yes**	**No**	**Comment**
			to other aspects of design and operation of electric facilities (such as public and worker safety) but do not need to be referenced in a vegetation management reliability standard.
Response: ▪ The FERC is no longer indicating a need to develop a requirement for a minimum inspection cycle (March 16, 2007 Order 693) and stakeholders indicated they did not support this change, so it was removed from the SAR. ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary. ▪ The Drafting Team recognizes that the IEEE standard is applicable. The FERC staff has questioned the applicability of the IEEE standard and the Drafting Team agreed to address their questions and concerns.			
TVA		☑	Minimum Inspection Intervals: FAC 003-1 provides the proper amount of flexibility regarding vegetation inspection cycles and that the Standards Drafting Team should not impose minimum inspection intervals on a continent with such regional diversity in climate and plant life. Requirement 1.1 of standard FAC-003-1 places the responsibility for proper inspection cycles on the entity that knows the local conditions and can best define what that inspection frequency should be, the Transmission Owner. Both NERC and the FERC staff have recognized that various local conditions can have an affect on the determination of adequate inspection frequencies. Establishing a mandatory minimum inspection frequency could have two detrimental effects on the industry. First, where a particular region is heavily forested and has heavy rainfall along with extended or year round growing seasons, a "back stop" minimum inspection frequency could lead transmission owners to conduct inspections less frequently than required by the local conditions. This could result in a Transmission Owner complying with the standard while not adequately protecting the reliability of that region's transmission system. This is a "lowest common denominator" approach which FERC has repeatedly stated is inappropriate for the reliability standards. Page 5 of 6 January 15, 2007 Second, where a particular region is arid, sparsely forested or has a minimum growing season, a "back stop" minimum could require a more frequent interval than is realistically needed. This would result in increased and unnecessary costs for electric utility customers without providing an increase in system reliability. In its

Question #2			
Commenter	**Yes**	**No**	**Comment**
			discussion of inspection intervals, FERC indicates that a “one-year vegetation inspection cycle is reasonable.” FERC NOPR, 10/20/2002 paragraph 383. The Commission continues by stating “a one-year inspection cycle is the ‘norm’ for the industry, but not the lowest common denominator…” It follows from this observation that the industry as a whole recognizes and follows appropriate inspection intervals without a need to change the standard. Further, FERC also states “some variation to a continent-wide, one-year minimum inspection cycle should be allowed due to physical differences such as climate and species of vegetation.” FERC NOPR 10/20/2006, paragraph 382. FERC’s recognition that a “one size fits all” approach is not appropriate supports maintaining the existing inspection requirements in standard FAC-003-1. Finally, the performance metrics of FAC-003 require the reporting of applicable transmission interruptions that are caused by vegetation. This process will identify Transmission Owners’ inspection cycles that are not adequate. In this event, the ERO has the authority to engage the Transmission Owner in enforcement compliance actions and, therefore, can remedy any vegetation-related outage that is attributed to the Transmission Owner’s inspection frequency. Standard Applicability: The 200 kV threshold for determining facilities subject to this standard should not be revised. The transmission facilities below 200 kV have not been cited as impacting bulk power system reliability. The Final Report on the August 14, 2003 Blackout in the United states and Canada: Causes and Recommendations April 2004 by the U.S.- Canada Power System Outage Task Force and all referenced major blackouts(pages 103-115) in that report, cited only outages which involved vegetation at line voltages above 200 kV. Generally applying requirements appropriate for 200 kV lines to lines less than 200 kV will result in significant documentation and reporting of items such as restrictions, mitigation plans, off right-of-way vegetation-related outage investigation/information and other issues, all of which dilutes the focus on lines that directly impact bulk power system reliability. Revising the standard to use general criteria or broad language for defining "Bulk Power System" transmission lines covered by the standard could become a “one size fits all” approach. If that approach were taken, the standard would cover a significant

Question #2			
Commenter	**Yes**	**No**	**Comment**
			number of transmission lines that have no direct impact on bulk power system reliability under standard planning/operating conditions, resulting in a significant increase in costs for electric customers without improving "Bulk Power System" system reliability. The SERC VMS believes that the applicability provision of the standard should instead focus attention of the standard only on the transmission lines below 200 kV that directly impact "Bulk Power System" reliability, as the current version requires. The applicability provision of this standard should be revised only if existing system design, planning or operating reliability criteria and parameters are considered as a basis for defining the applicability of the standard. To that end, each Regional Entity (RE) should determine the applicability of FAC-003 to those lines within the region that are between 100 kV and 200 KV if and only if they are identified as operationally significant elements of Interconnection Reliability Operating Limits ("IROLs"). IEEE Standard for Minimum Clearances: Page 6 of 6 January 15, 2007 The IEEE 516-2003 should continue to be used as the minimum acceptable distances for "Clearance 2". The IEEE 516-2003 tables are appropriate for defining the minimum acceptable clearances to prevent flashover between conductors and vegetation under all rated electrical operating conditions. Closer minimum clearances such as the minimum length of a support insulator could have been adopted as a "lowest common denominator" clearance. However the clearance in IEEE 516-2003 was adopted to ensure an additional margin of reliability. FERC staff references ANSI Z-133 which is a safety standard that addresses worker safety as well as the safety of the general public. As such, the purpose of ANSI Z-133 is to address worker safety and is not focused on transmission line reliability, which is the purpose of FAC-003-1. OSHA, NESC and other related safety standards have clearances in excess of IEEE 516-2003. Those clearances are clearly focused on safety issues and will still apply to other aspects of design and operation of electric facilities (such as public and worker safety) but do not need to be referenced in a vegetation management reliability standard.
Response:			

Question #2			
Commenter	**Yes**	**No**	**Comment**
▪ The FERC is no longer indicating a need to develop a requirement for a minimum inspection cycle (March 16, 2007 Order 693) and stakeholders indicated they did not support this change, so it was removed from the SAR. ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary. ▪ The Drafting Team recognizes that the IEEE standard is applicable. The FERC staff has questioned the applicability of the IEEE standard and the Drafting Team agreed to address their questions and concerns.			
Midwest Reliability Organization	☑	☑	The scope of this SAR would have been better defined if the complete Standard Review Form for the Vegetation Management Standard had been included as an attachment to the SAR. Several issues in the Standard Review Form for this SAR were excluded with this posted SAR. For example, issues related to R3.1 and R3.2. The MRO is also not clear on the scope of the instruction to the SDrafting Team to "Expand the applicability to include transmission lines operated at 200 kV and above and other facilities as determined by the ERO so that the Reliability Standard applies to Bulk-Power System transmission lines that have an impact on reliability" It is not clear to the MRO what is meant by "as determined by the ERO". What process will the ERO use? The ERO should use stakeholder input to make this determination. The current standard is applicable to all transmission lines 200 kV and above and to any lower voltage lines designated by the RRO as critical to the electric system in the region. Will the ERO be in a position to assume the assessment of the criticality of lines less than 200 kV without input from the entities that have historically operated in each region? Also, the MRO is not clear on what is included in the term Bulk-Power System. What guidance will the SDrafting Team have in determining what is meant by the Bulk-Power System? Since this relates to the large issue of the Bulk Electric System versus Bulk-Power System is this SAR the appropriate vehicle to address this issue? There should be a wider discussion and resolution to this issue for consistent application to all standards by all SDrafting Teams.
Response: ▪ The comments on R3.1 and R3.2 were developed by NERC staff in a previous version of this SAR and these have been deleted from the revised SAR. Instead, the Standard Drafting Team will apply the Standard Review Guidelines to the Standard. ▪ The comments from the FERC NOPR were removed from the revised SAR. ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary.			
Florida Power and Light Company		☑	Establishing minimum inspection cycles is a very problematic given the large variety of vegetative conditions throughout North America. In reality most lines are inspected annually for all failure modes including vegetation. The trees that played a part of the North East Blackout were known and on the radar screen. The utility

Question #2			
Commenter	**Yes**	**No**	**Comment**
			failed to take action. The inspection did not prevent the outage from occurring. The failure to take action on the known site condition was the contributing factor to the Blackout. We do not understand the need to establish separate criteria other than the RRO's critical designation. A transmission line is either necessary to the system to prevent an overload situation or it is not. To add lines that might not be critical to the system would dilute the effort needed to insure that the critical lines are properly maintained. Since system stability is the focus of the standard, what criteria would be used to bring additional lower voltage lines under the standard. When developing Clearance 2, the committee needed to determine a distance at which a Transmission Owner could be out of compliance even though no interruption has occurred. In a sense this is the maximum 'speed limit' at which the utility would be in violation. Their criteria was "How close can a tree be and not cause an outage?" The engineers on the team reviewed scientific data and current standards. The IEEE MAID standard was the consensus selection of the sub committee. All parties need to understand that this is one of the building blocks that would be used in determining the width of an easement or ROW. Picking the ANSI Z133.1 Table 1 or 2 as the NOPR suggests could immediately place thousands of miles of transmission lines out of compliance that have performed satisfactorily for years. The ANSI tables are phase to phase safety calculations when grow-in tree interruptions are phase to ground situations.
Response: ▪ The FERCis no longer indicating a need to develop a requirement for a minimum inspection cycle (March 16, 2007 Order 693) and stakeholders indicated they did not support this change, so it was removed from the SAR. ▪ The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes: o Re-format FAC-003-1 to conform to the current Standards Development Procedure. o Remove references to RRO in the standard and substitute a responsible entity. o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels.			
Public Service Commission of South Carolina		☑	We are concerned that lowering the applicability threshold to all lines below 200KV will divert attention and resources from the higher voltage lines which have a higher probability of causing grid problems. The RRO and transmission owners best know which lower voltage lines should be included under the requirements of the

Question #2			
Commenter	**Yes**	**No**	**Comment**
			standard.
Response: ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary.			
IESO Ontario		☑	With respect to the item in the Brief Description section under FERC NOPR: "Remove the applicability to transmission lines operated at 200 kV and above so that the Reliability Standard applies to Bulk Power System transmission lines that have an impact on reliability as determined by the ERO." It is the IESO's view that requiring the ERO to make these determinations, is inappropriate. We believe the standard should remain applicable to lines 200 kV and above and lines below 200 kV as determined by the Reliability Coordinator, similar to the PRC-023 standard. The IESO also suggests that it be made clear in the SAR that it will be a complete review of the subject requirements: to include the addition, deletion and modification of requirements, as agreed to by public consensus.
Response: ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to transmission voltage class <200kV is necessary. ▪ The Drafting Team removed the paragraph in the brief description of the SAR that opened the scope to other improvements. The Drafting Team concurs with consensus of the commenters that the technical elements of this standard are complete. The intent of the SAR modification is to address FERC issues and to conform to updates in the Reliability Standards Development Procedure and Sanctions Guidelines.			
Dominion - Electric Transmission		☑	We disagree with the proposal from FERC NOPR regarding removing applicability to transmission lines >200kv. The proposal to apply the Standard to lines the ERO deems to have an impact on reliability can create inconsistency between regions and is a "fill in the blank" requirement. It is not clear whether the proposed change would increase or decrease the number of transmission lines which are subject to reportable outages. In addition, we support the Standard's existing language that limits reporting to locked out lines only.
Response: ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary.			
Southern California Edison		☑	The Commission's reccomendation to develop a "minimum" vegetation inspection cycle is untimely and their proposal to revise the scope ignores plain language contained in the standard. In SCE's view, the Commission's incessant need to bolt on a "widget count" requirement (for minimum inspection cylcles) will likely lead to an increased number of tree-to-line contacts. Unlike the static equipment located in power plants

Question #2			
Commenter	**Yes**	**No**	**Comment**
			and substations, trees and foliage in and around Transmission ROWs are subject to uncontrolable and fairly unpredictable natural forces. Industry debate during the previous SAR and comments submitted in the recently concluded NOPR demonstrate this approach is unsound. Transmission Owners in neighboring states commented that their cycles and trimming protocols vary from year to year and sometimes circuit to circuit. Instituting a minimum inspection cycle of 3 years (for example) might appeal to certain TOs because doing so will support a case for increased rate recovery. But for others, a mandatory 3 year inspection cycle will offer a potential cost reduction opportunity because they are already following a voluntary 2 year inspection cycle. The Commission's other reccomendedation should be rejected because subsection 4.3 clearly covers transmission lines operating below 200 kV. ["….any lower voltage lines designated by the RRO as critical to the reliabilty of the electric system in the region."] FAC-003-1 requires Transmission Owners to - "define a schedule for and the type (aerial, ground) of ROW vegetation inspections". Although the Commission staff would prefer a specific time duration because it suits their "check list" style of enforcement, the prudent thing to do is allow TOs the latitude to manage their part of the bulk system and hold each accountable to the existing compliance measures in FAC-003-1. Similarly, revising subsection 4.3 in deferrence to the Commission's or staff's misinterpretation of plain text is unwarranted.
Response: ▪ The FERC is no longer indicating a need to develop a requirement for a minimum inspection cycle in its March 16, 2007 Order 693 and stakeholders indicated they did not support this change, so it was removed from the SAR. ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary.			
New York State Electric and Gas Corporation		☑	The current standard FAC 003 1 should be monitored for one to two full years after all segments have been implemented. February 14, 2007 is too soon to determine if a revision is required. The standard should apply to 200 KV lines and higher voltages to prevent cascading type power outages. The IEEE table 516 is referenced as a minimum guide for table 2 clearances. This table provides clear and measurable distances that can used for audits and

Question #2			
Commenter	**Yes**	**No**	**Comment**
			potential compliance issues. The current standard allows enough flexibility so that the clearance 2 distance can be expanded if a utility feels that is the correct approach in a specfic region. The physical differences between electric systems, tree growth rates, local regulations, climate, and geography make it important to provide a flexible standard, a "one size fits all" approach will not be effective in the long run.

Response:
▪ The ERO Rules of Procedure include the latest versions of the Reliability Standards Development Procedure Manual and the Sanctions Guidelines. These documents were approved following the approval of FAC-003-1. FAC-003-1 will need to be revised to bring the standard into conformance with these documents.
▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary.
▪ The Drafting Team recognizes that the IEEE standard is applicable. The FERC staff has questioned the applicability of the IEEE standard and the Drafting Team agreed to address their questions and concerns.
▪ The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes:
  o Re-format FAC-003-1 to conform to current Standards Development Procedure.
  o Remove references to RRO in the standard and substitute a responsible entity.
  o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels.
▪ The FERC is no longer indicating a need to develop a requirement for a minimum inspection cycle (March 16, 2007 Order 693) and stakeholders indicated they did not support this change, so it was removed from the SAR.			

Manitoba Hydro		☑	The scope of the SAR is too vague on several important points. (1) There is no definition for the phrase bulk-power system - it would be therefore unclear as to what facilities would be covered by the standard. What guidance will the SDrafting Team have in determining what is meant by the bulk-power system? Since this relates to the large issue of the Bulk Electric System versus Bulk-Power System is this SAR the appropriate vehicle to address this issue? There should be a wider discussion and resolution to this issue for consistent application to all standards by all SDrafting Teams. (2)The concept of Mitigation Time Horizons has not been defined and the use of Mitigation Time Horizons has not been detailed. (3)The ERO is not the appropriate entity to determine which lines have an impact on reliability. This should be Transmission Operators in coordination with Reliability Coordinators. If this standard is to include the methodology to determine which lines have a reliability impact on the bulk-power system, the the applicability of the

Question #2			
Commenter	**Yes**	**No**	**Comment**
			standard will have to include other entities besides the Transmission Owners. (4) The SAR refers to RA, i.e., Reliability Authority. This entity no longer exists in the Functional Model but has been replaced by Reliability Coordinator. (5) What is meant by "Too weak on compliance"? (5) FERC objects to IEEE Standard but there is no other guidance to the standard drafting team.
Response: ▪ The comments regarding Bulk Power System in the FERC NOPR comments were removed from the revised SAR. ▪ The ERO Rules of Procedure require the inclusion of time horizons for each standard – these are defined in the Sanctions Guidelines and are used to help determine the size of a sanction. ▪ The revised SAR does not include the language proposing that the ERO determine which lines have an impact on reliability. ▪ The reference to Reliability Authority (RA) was removed from the revised SAR. ▪ The reference, 'Too weak on compliance' was removed from the revised SAR as it was addressed with the development of Version 1 of this standard. ▪ The Drafting Team recognizes that the IEEE standard is applicable. The FERC staff has questioned the applicability of the IEEE standard and the Drafting Team agreed to address their questions and concerns.			
Southern Company Transmission		☑	The scope of the SAR should be limited to formatting and changes of wording that recognize the formation of the ERO and its procedures. The drafting team should not attempt to re-write the present clearance requirements, which are based on IEEE flashover distances. The clearance requirements in the orignal standard were written through extensive evaluation and input from the industry. There was strong industry consensus on the present language and the standard is serving its intended purpose very well. The clearance standard should not be revised until it is found to be ineffective or inadequate. The drafting team should not attempt to change the applicability of the present standard. The present standard applies to all 200 KV and higher lines, plus any other line the Regional Entity deems critical. A change in wording to make the standard apply to any bulk power system transmission line deemed critical by the ERO does not provide any additional safeguard that is not already contained in the standard as presently written.
Response: ▪ The Drafting Team recognizes that the IEEE standard is applicable. The FERC staff has questioned the applicability of the IEEE			

Question #2			
Commenter	**Yes**	**No**	**Comment**
standard and the Drafting Team agreed to address their questions and concerns. ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary.			
Baltimore Gas and Electric		☑	As noted above.
Response: See response to your question #1 comment above.			
Salt River Project	☑		
Allegheny Power	☑		

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

Summary Consideration: Commenters suggested a number of additional revisions to the SAR related to:

- Applicability
- Right of Way (ROW) definition
- Compliance
- Clearance requirements
- Others

The SAR Drafting Team revised the SAR to consider these suggested revisions.

Question #3			
Commenter	**Yes**	**No**	**Comment**
Bonneville Power Administration	☑		It is not clear if categroy 1 and 2 refer only to occupied ROW, or also to unoccupied area reserved by the Transmission Owner for future expansion.
Response: o Category 1 outages refer to "grow-ins" inside or outside the right-of-way regardless; while a Category 2 outage applies to "fall-ins" on land that is inside the legal bounds of the right-or-way whether occupied or not. ▪ The FERC has directed the ERO to address the definition of ROW in its Order 693. ▪ As part of the SAR, the SAR Drafting Team commits the Standard Drafting Team to prepare technical reference material such as a "white paper" to aid in understanding the technical basis for the standard and, unless the requirements in the standard are modified to add more clarity, the SAR Drafting Team will recommend that the white paper include a discussion of the differences between category 1 and category 2 to address your concern.			
FRCC	☑		Requirement 3.2, item (1), the reporting exemption for outages occuring due to natural disaters should be expanded to include all vegetation outages that occur as a result of the disaster. Currently the exemption applies to vegetation from outside the ROW. As a result of significant experience with hurricanes, our operators have found that this distinction results in a waste of post-disaster resources. The standard currently requires the owner to investigate and determine the original location of the vegetation that may have caused an outage. Restoration of circuits may be delayed and often times, determination of the original location of the vegetation is not possible.
Response: ▪ The SAR Drafting Team will review the reporting exemptions to all category outages under major disasters in Requirement R3.2.			
Northeast Power Coordinating Council	☑		Only if the Bulk Power System is determined as an impact based performance based methodology.
Response:			

Question #3			
Commenter	**Yes**	**No**	**Comment**
▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary. The comments regarding Bulk Power System in the FERC NOPR comments were removed from the revised SAR ▪			
SERC Reliability Corporation	☑		Standard Applicability: The outage reporting requirement for the RRO should be deleted. Making FAC-003 applicable to the RRO is in violation of the legislation that established the ERO. This legislation states that enforceable standards can apply only to owners, users and operators of the bulk power system. Futher, in the NOPR on NERC standards, FERC declined to approve those standards that applied to the RROs, in part because the RROs are not owners, users or operators. Compliance: The SERC VMS recommends deleting reporting requirements for Category 3 outages. These outages are not controllable, not relevant to compliance, not related to grid reliability, not related to cascading blackouts, and such reporting leads to unnecessarily biasing reliability related information.
Response: ▪ The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes: o Re-format FAC-003-1 to conform to the current Standards Development Procedure. o Remove references to RRO in the standard and substitute a responsible entity. o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels. ▪ The Standard Drafting Team intends to review reporting criteria for Category 3 outages in the proposed technical reference material and may review the reporting requirement of Category 3 outages in R.3 and R.4.			
Progress Energy	☑		Standard Applicability: The outage reporting requirement for the RRO should be deleted. Making FAC-003 applicable to the RRO is in violation of the legislation that established the ERO. This legislation states that enforceable standards can apply only to owners, users and opeartors of the bulk power system. Futher, in the NOPR on NERC standards, FERC declined to approve those standards that applied to the RROs, in part because the RROs are not owners, users or operators. Compliance: Progress Energy believes that FAC-003 should focus compliance on the issues that improve system/grid reliability. The VM standard outage reporting requirements do not focus on ensuring grid/network reliability.

Question #3			
Commenter	**Yes**	**No**	**Comment**
			Category 2 outages ("Fall-ins" from vegetation within the R/W) result in a level of non-compliance (Level 2 or 3). However, "Fall-ins", either off-R/W or within the R/W, are random events. They would not occur sequentially (i.e., a fall-in causing another line section to overload resulting in another "fall-in") and would not have the potential to cascade into a widespread blackout. This is a customer reliability issue for that line, not a grid reliability issue. While it may be worthwhile to report for tracking and trending, it is not an outage that should result in non-compliance. Category 1 "Grow-ins" include outages that result from conductor side-wing would be reported as Category 1 outages, resulting in non-compliance (Level 3 or 4). However, conductor side-swing outages are random occurrences. They are not the sequential outages that would have the potential to cascade into a widespread blackout. This is a customer reliability issue for that line, not a grid reliability issue. These types of outages should be not be considered any different than numerous other random events that result in transmission line outages.
Response: ▪ The SAR Drafting Team understands the distinction between grow-in and fall-in related outages and the prediction challenges with fall-in related outages. Modifying the compliance section is included in the scope of the SAR.			
Florida Power and Light Company	☑		Requirement 3.2 exempts reporting of outages from outside the ROW when natural disasters such as tornados or hurricanes occur. Our experience with numerous hurricanes indicates that all outages during these types of events should be exempt. The focus in these situations is to get the lines back in service and restore customers. There is insufficient manpower to adequately complete the forensics necessary to determine an accurate root cause. It is not uncommon to find vegetation debris in the lines or downed trees on the ROW in this situation. In most cases it is not possible to determine the original location of these trees. In the compliance section of the document a transmission owner becomes non compliant with a single category 1 or 2 outage. This occurs regardless of the circumstances. A non compliant penalty for a single outage in a situation where no customers were affected and the system could not have been compromised is not reasonable. It is also not an indicator of a poorly maintained system. We agree that several Category 1 or 2 interruptions could be an indicator of neglect but one is not. We recommend that The compliance section be reviewed with this in mind.
Response: ▪ The Standard Drafting Team will review the reporting exemptions to all category outages under major disasters in Requirement			

Question #3			
Commenter	**Yes**	**No**	**Comment**
R3.2. ▪ Modifying the compliance section is included in the scope of the SAR.			
Midwest Reliability Organization	☑		Since the IEEE standard does not appear to be a favorable clearance requirement, minimum clearance requirements should be tied to legal documents such as easments, state statute, or permits. This will help Transmission Owners to maintain their ROWs based on their agreements with the land owners and not rely on historical ROW management practices. It would also provide flexibility in clearance requirements based on geopraphical and climatological factors that influence different regions because landowner agreements will be different depending on local influences.
Response: ▪ The Drafting Team recognizes that the IEEE standard is applicable. The FERC staff has questioned the applicability of the IEEE standard and the Drafting Team agreed to address their questions and concerns.			
TVA	☑		Standard Applicability: The outage reporting requirement for the RRO should be deleted. Making FAC-003 applicable to the RRO is in violation of the legislation that established the ERO. This legislation states that enforceable standards can apply only to owners, users and operators of the bulk power system. Further, in the NOPR on NERC standards, FERC declined to approve those standards that applied to the RROs, in part because the RROs are not owners, users or operators. Compliance: Reporting requirements for Category 3 outages should be eliminated. These outages are not controllable, not relevant to compliance, not related to grid reliability, not related to cascading blackouts, and such reporting leads to unnecessarily biasing reliability related information.

Response:
▪ The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes:
    o Re-format FAC-003-1 to conform to the current Standards Development Procedure.
    o Remove references to RRO in the standard and substitute a responsible entity.
    o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels.
▪ The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.
▪ The Standard Drafting Team intends to review reporting criteria for Category 3 outages in the proposed technical reference material and may review the reporting requirement of Category 3 outages in R.3 and R.4.			

<table>
<tr><th colspan="4">Question #3</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td>Bandera Electric Coop.</td><td></td><td>☑</td><td>See Comment #2</td></tr>
<tr><td colspan="4">Response: See response to Comment #2.</td></tr>
<tr><td>ITC Transmission</td><td></td><td>☑</td><td>We think the Standard is fine the way it is.</td></tr>
<tr><td colspan="4">Response:
▪ The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes:
o Re-format FAC-003-1 to conform to the current Standards Development Procedure.
o Remove references to RRO in the standard and substitute a responsible entity.
o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels.
▪ The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.</td></tr>
<tr><td>American Electric Power</td><td></td><td>☑</td><td>As stated in responses to questions 1 and 2, AEP believes that the current standard is adequate and that we are not aware of evidence to support a need for revising the current vegetation management standard.</td></tr>
<tr><td colspan="4">Response:
▪ The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes:
o Re-format FAC-003-1 to conform to the current Standards Development Procedure.
o Remove references to RRO in the standard and substitute a responsible entity.
o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels.
▪ The Standard Drafting Team will address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.</td></tr>
<tr><td>Southern California Edison</td><td></td><td>☑</td><td>Although SCE is wholly dissatisfied with the integration of IEEE 516-2003 into FAC-003-1 and looks forward to the day when qualified industry professionals and utility arborists are provided an opportunity to develop a reasonable and scientifically sound method for determining “minimum” tree-to-line clearances, we believe this standard should be allowed to “soak” a bit before subjecting it to further revision.</td></tr>
<tr><td colspan="4">Response:
▪ The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes:
o Re-format FAC-003-1 to conform to the current Standards Development Procedure.
o Remove references to RRO in the standard and substitute a responsible entity.
o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels.
▪ The Standard Drafting Team will address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.
▪ The Drafting Team recognizes that the IEEE standard is applicable. The FERC staff has questioned the applicability of the IEEE standard and the Drafting Team agreed to address their questions and concerns.</td></tr>
</table>

Question #3			
Commenter	**Yes**	**No**	**Comment**
New York State Electric and Gas Corporation		☑	The Vegetation Management Standard FAC 003 1 is comprehensive, and utilities following the established guidelines will be able to meet FERC's expecation of preventing bulk power delivery outages by using crisp measurable guidleines that offer limited flexiblity for varying conditions.
Response: ▪ The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes: o Re-format FAC-003-1 to conform to the current Standards Development Procedure. o Remove references to RRO in the standard and substitute a responsible entity. o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels, etc. ▪ The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.			
ISO/RTO Council Standards Review Committee		☑	
Hydro One Networks, Inc.		☑	
Allegheny Power		☑	
Dominion - Electric Transmission		☑	
CenterPoint Energy Houston Electric, LLP		☑	
ISO New England		☑	
Central Hudson Gas & Electric		☑	
Public Service Commission of South Carolina		☑	
Hydro-Québec TransÉnergie		☑	
Southern Company Transmission		☑	
IESO Ontario		☑	
Salt River Project		☑	
Baltimore Gas and Electric		☑	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on Second Draft of Vegetation Management SAR (Project 2007-07)

The Vegetation Management SAR drafting team thanks all commenters who submitted comments on Draft 2 of the SAR. This SAR was posted for a 30-day public comment period from April 20 through May 9, 2007. The drafting team asked stakeholders to provide feedback on the SAR through a special SAR Comment Form. There were 27 sets of comments, including comments from 65 different people from more than 50 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the drafting team recommends that the Standards Committee advance this SAR to the standard drafting step of the standard development process. The drafting team made only one minor modification to the SAR to clarify (on page 2) that it is the ERO that will collect vegetation-related transmission outage data, not the SDT.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Vegetation-Management_Project_2007-7.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Anita Lee (G1)	AESO		✓								
2.	Jay Farrington (G5)	Alabama Electric Coop.	✓									
3.	Randy Gann (G5) (G6)	Alabama Power	✓									
4.	Ken Goldsmith (G6)	ALT										✓
5.	Mary Hetz	Ameren	✓									
6.	Raymond Wiesehan (G5)	Ameren	✓									
7.	Thad Ness	American Electric Power	✓				✓	✓				
8.	John Neagle (G5)	Associated Electric Coop.	✓									
9.	William T. Rees, Jr.	Baltimore Gas & Electric										
10.	Dave Rudolph (G6)	Basin Electric Power Coop.										✓
11.	Brent Kingsford (G1)	CAISO		✓								
12.	John R. Kellum, Jr.	CenterPoint Energy	✓									
13.	Weston J. Davis	Central Maine Power	✓									
14.	CJ Ingersoll	Constellation (CEDC)			✓							
15.	Gene Walton	Dominion	✓									
16.	Gregory Rowland	Duke Energy	✓		✓		✓	✓				
17.	Billy George (G5)	Duke Energy, Carolinas	✓									
18.	Ralph Hale (G5)	Entergy	✓									
19.	Paul D. Olivier	Entergy Corporation	✓									
20.	Steve Myers (G1)	ERCOT		✓								
21.	Marc Tunstall (G5)	Fayetteville Public Works Comm.	✓									
22.	Doug Hohlbaugh	FirstEnergy Corp.	✓									
23.	John Tamsberg	Florida Power & Light Co.	✓									
24.	Nancy Huddleston (G6)	Georgia Power Co.	✓									
25.	Joe Knight (G6)	Great River Energy										✓
26.	Steve Burns (G6)	Gulf Power Co.	✓									

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
27.	Ken Trump (G6)	Gulf Power Co.	✓									
28.	David Kiguel	Hydro One Networks Inc.	✓									
29.	George Juhn	Hydro One Networks Inc.	✓									
30.	Roger Champagne	Hydro-Québec TransÉnergie (HQT)	✓									
31.	Ron Falsetti (I) (G1)	Independent Electricity SO		✓								
32.	Matt Goldberg (G1)	ISO-NE		✓								
33.	Kathleen Goodman (I) G2)	ISO-NE		✓								
34.	Robert Coish (I) (G6)	Manitoba Hydro	✓		✓		✓	✓				
35.	Terry Bilke (G6)	Midwest ISO										✓
36.	Mike Brytowski (G6)	Midwest Reliability Organization										✓
37.	Carol Gerou (G6)	Minnesota Power										✓
38.	Bill Phillips (G1)	MISO		✓								
39.	Steve Craig (G6)	Mississippi Power Co.	✓									
40.	Ron Reinike (G6)	Mississippi Power Co.	✓									
41.	Thomas E. Sullivan	National Grid	✓									
42.	Anthony Johnson	Northeast Utilities		✓								
43.	Mike Calimano (I) (G1)	NYISO		✓								
44.	Todd Gosnell (G6)	OPPD										✓
45.	Stephen Tankersley	Pacific Gas and Electric Co. (PGE)	✓									
46.	Alicia Daugherty (G1)	PJM		✓								
47.	Jack Gardner (G3) (G5)	Progress Energy Carolinas	✓									
48.	John Pinney (G3)	Progress Energy Florida	✓									
49.	Philip Riley (G4)	Public Service Commission SC									✓	
50.	Mignon L. Clyburn (G4)	Public Service Commission SC									✓	
51.	Elizabeth B. Fleming (G4)	Public Service Commission SC									✓	
52.	G. O'Neal Hamilton (G4)	Public Service Commission SC									✓	
53.	John E. Howard (G4)	Public Service Commission SC									✓	
54.	Randy Mitchell (G4)	Public Service Commission SC									✓	
55.	C. Robert Moseley (G4)	Public Service Commission SC									✓	

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
56.	David A. Wright (G4)	Public Service Commission SC									✓	
57.	John Wolfmeyer (G5)	SERC										✓
58.	Jerry Lindler (G5)	South Carolina E&G	✓									
59.	Roman Carter (G6)	Southern Transmission	✓									
60.	Charles Yeung (G1)	SPP		✓								
61.	Richard Dearman (I) (G5)	TVA	✓									
62.	Jeffrey S. Disorda	VELCO	✓									
63.	Jim Haigh (G6)	WAPA										✓
64.	Neal Balu (G6)	WPSR										✓
65.	Pam Oreschnick (G6)	Xcel Energy										✓

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 – IRC Standards Review Committee (IRC SRC)
G2 – NPCC CP9 Reliability Standards Working Group (NPCC CP9)
G3 – Progress Energy Carolinas/Progress Energy Florida (PGN)
G4 – Public Service Company of South Carolina (PSC SC)
G5 – SERC Vegetation Management Subcommittee (SERC VMS)
G6 – Southern Company Transmission
G7– MRO Members

Index to Questions, Comments, and Responses

1. **Do you agree there is a reliability need for the proposed modifications and review of the standard?**

Summary Consideration: Most commenters noted that while the FAC-003-1 Standard is technically adequate, they believed that clarification in the form of a technical white paper, and review of applicability parameters is warranted. Many of these commenters also agreed with the need to update the standard to conform to new procedural requirements and inclusion of compliance elements. The SDT shall consider producing a white paper to aid in clarifying the intent of the standard.

Question #1			
Commenter	**Yes**	**No**	**Comment**
AEP		☑	AEP believes that the current standard (when thoroughly read and understood) is completely adequate to maintain a reliable transmission system with minimum risk of vegetation-related outages.
Response: The team concurs that the technical elements are generally adequate and there is no reliability need to revise the standard. However all NERC standards must be updated to comply with new procedural requirements and inclusion of compliance elements. The Standard DT will address the issues raised in the FERC's March 16, 2007 Order 693 - Mandatory Reliability Standards for the Bulk Power System. The SDT shall consider producing a white paper to aid in clarifying the intent of the standard.			
Baltimore Gas & Electric		☑	I'm not convinced that the elements outlined in the proposal will improve reliability and have concerns that the proposed modifications may actually reduce the flexibility that is necessary to promote system reliability or to comply with local regulations. I would prefer to see more specifics in the proposal before supporting the modifications.
Response: The team concurs that the technical elements are generally adequate and there is no reliability need to revise the standard. However all NERC standards must be updated to comply with new procedural requirements and inclusion of compliance elements. The Standard DT will address the issues raised in the FERC's March 16, 2007 Order 693 - Mandatory Reliability Standards for the Bulk Power System. The SDT shall consider producing a white paper to aid in clarifying the intent of the standard.			
CenterPoint Energy		☑	CenterPoint Energy does not agree that a revision to the TVM standard is necessary from a reliability standpoint, and believes that the existing TVM standard is adequate for that purpose.
Response: The team concurs that the technical elements are generally adequate and there is no reliability need to revise the standard. However all NERC standards must be updated to comply with new procedural requirements and inclusion of compliance elements. The Standard DT will address the issues raised in the FERC's March 16, 2007 Order 693 - Mandatory Reliability Standards for the Bulk Power System. The SDT shall consider producing a white paper to aid in clarifying the intent of the standard.			
Central Maine Power		☑	The current Vegetation Management Standard FAC-003-1 has been crafted in such a way as to provide crisp measurable standards that when followed will provide a high level of power quality for the bulk power delivery system. However, clearances between

Question #1			
Commenter	**Yes**	**No**	**Comment**
			conductors and trees required to prevent tree related power outages must be consistent with each utility's established standards and if a transmission line passes through federal, state or locally managed areas this line placement should not impact the established clearances. Utilities should not be expected to negotiate clearances with multiple land managers. The IEEE 516 – 2003 table is an acceptable table to use as the minimum clearance to prevent a flash over and outages. FAC-003-1 is designed to be a reliability standard and the industry adheres to OSHA and ANSI standards to protect workers and the public. The IEEE 516 – 2003 table lists appropriate distances that should be used to measure compliance. The standard should continue to provide the flexibility for utility managers to increase "Clearance 2". The definition for right-of-way should be clarified to include only the area that is cleared and included as routine maintenance. We agree that there is a need to establish time horizons and clarify violation levels.
Response: The team concurs that the technical elements are generally adequate and there is no reliability need to revise the standard. However all NERC standards must be updated to comply with new procedural requirements and inclusion of compliance elements. The Standard DT will address the issues raised in the FERC's March 16, 2007 Order 693 - Mandatory Reliability Standards for the Bulk Power System, including a review of the definition for right-of-way. The SDT shall consider producing a white paper to aid in clarifying the intent of the standard.			
Duke Energy		☑	From a reliability perspective, the current standard contains appropriate requirements and measures to ensure the Transmission Owner's vegetation management program is implemented and managed to ensure the reliability of the transmission system. However the standard should be revised to address non-reliability related items that are in the SAR.
Response: The SAR DT agrees and thanks you for the comment.			
HQT		☑	It is our belief that the Standard in its current form does provide adequate provisions and drivers to minimize vegetation related outages and eliminate the likelihood of reoccurence of the August 14, 2003 blackout. However, it is recognized that the industry needs to consolidate its view on these provisions and we support the preparation of a "white paper" that will document the rationale concerning the requirements of the standard, as well as review certain aspects of the standard that have come into question.
Response: The SAR DT agrees and thanks you for the comment.			

Question #1			
Commenter	**Yes**	**No**	**Comment**
Hydro One Networks		☑	It is our belief that the Standard in its current form does provide adequate provisions and drivers to minimize vegetation related outages and eliminate the likelihood of reoccurence of the August 14, 2003 blackout. However, it is recognized that the industry needs to consolidate its view on these provisions and we support the preparation of a "white paper" that will document the rationale concerning the requirements of the standard, as well as review certain aspects of the standard that have come into question.
Response: The SAR DT agrees and thanks you for the comment.			
National Grid		☑	National Grid believes that compliance with all elements of the present Standard will result in TO's achieving the reliability objectives set forth in the Standard.
Response: The SAR DT agrees and thanks you for the comment.			
Northeast Utilities		☑	Proposed modifications do not increase the levels of reliability above what is already required in the current version of the Stnadard.
Response: The team concurs that the technical elements are generally adequate and there is no reliability need to revise the standard. However all NERC standards must be updated to comply with new procedural requirements and inclusion of compliance elements. The Standard DT will address the issues raised in the FERC's March 16, 2007 Order 693 - Mandatory Reliability Standards for the Bulk Power System. The SDT shall consider producing a white paper to aid in clarifying the intent of the standard.			
PGN		☑	Progress Energy Carolinas and Progress Energy Florida are providing an answer to the question as it relates to the reliability need. The current standard contains appropriate requirements and measures to ensure the Transmission Owner's vegetation management program is implemented and managed to ensure the reliability of the transmission system. In addition, we do not believe that a standard with a zero tolerance for vegetation-related outages in the ROW is in need of reliability-based revisions. However, we do recognize the need for a revision of the standard to address non-reliability related items that are in the SAR. Procedural items such as formatting and clarifications, such as the definition of right-of-way, need to be, and should be, addressed.
Response: The team concurs that the technical elements are generally adequate and there is no reliability need to revise the standard. However all NERC standards must be updated to comply with new procedural requirements and inclusion of compliance elements. The Standard DT will address the issues raised in the FERC's March 16, 2007 Order 693 - Mandatory Reliability Standards for the Bulk Power System. The SDT shall consider producing a white paper to aid in clarifying the intent of the standard.			

Question #1			
Commenter	**Yes**	**No**	**Comment**
SERC VMS		☑	The SERC VMS is providing an answer to the question as it relates to the reliability need. The current standard contains appropriate requirements and measures to ensure the Transmission Owner's vegetation management program is implemented and managed to ensure the reliability of the transmission system. In addition, we do not believe that a standard with a zero tolerance for vegetation-related outages in the ROW is in need of reliability-based revisions. However the SERC VMS recognizes the need for a revision of the standard to address non-reliability related items that are in the SAR. Procedural items such as formatting and clarifications, such as the definition of right-of-way, need to be, and should be, addressed.
Response: The team concurs that the technical elements are generally adequate and there is no reliability need to revise the standard. However all NERC standards must be updated to comply with new procedural requirements and inclusion of compliance elements. The Standard DT will address the issues raised in the FERC's March 16, 2007 Order 693 - Mandatory Reliability Standards for the Bulk Power System. The SDT shall consider producing a white paper to aid in clarifying the intent of the standard.			
CECD	☑		Modifications to capture the Commissions concerns must be addressed therefore these actions are appropriate.
Response: The Standard DT will address the issues raised in the FERC's March 16, 2007 Order 693 - Mandatory Reliability Standards for the Bulk Power System.			
Dominion	☑		We support reinstating the 200kv threshold for reportable events.
Response: The Standard DT will review applicability as requested by the FERC. See also the drafting team responses to question #2.			
Entergy Corp.	☑		The existing FAC-003-1 is flawed and needs revision.
Response: The SAR DT agrees that revisions of this standard are needed primarily to comply with new procedural requirements and inclusion of compliance elements as well as address issues raised in the FERC's March 16, 2007 Order 693 – Mandatory Reliability Standards for the Bulk Power System.			
FirstEnergy Corp.	☑		FirstEnergy agrees that clarification on select issues will aid the intent of this NERC Standard.
Response: The SAR DT agrees and thanks you for the comment.			
Florida Power & Light	☑		FPL believes the technical portion of the standard provides adequate reliability protection to the system. FPL also recognizes the need to re-format the standard to bring it into conformance with the latest version of the Reliability Standard Development Procedure and the ERO Sanctions Guidelines, to remove references to RRO in the standard and substitute a responsible entity and, add compliance elements such as time horizons, and

Question #1			
Commenter	**Yes**	**No**	**Comment**
			violation severity levels.
Response: The SAR DT agrees and thanks you for the comment.			
IESO	☑		
IRC SRC	☑		
ISO-NE	☑		
Manitoba Hydro	☑		The definition of ROW should be clarified. The definition of a critical line should not be kept to a particular voltage threshold. However, consideration could also then be given to exempting non-critical lines operating at higher voltage levels (>200kv). Electrical clearances should be consistent whether on Federal or non-Federal land.
Response: The standard DT will review the definition of ROW. The standard DT will review applicability parameters of this standard, taking into account the comments from stakeholders such as NU, National Grid, Manitoba Hydro, First Energy, and others. The SAR DT concurs with the commenter with respect to applying this standard to Federal and non-Federal lands. The standard DT will evaluate the suitability of a case-by-case approach.			
MRO	☑		
NYISO	☑		
PGE	☑		As stated in the SAR.
Response: The SAR DT agrees and thanks you for the comment.			
PSC SC	☑		
Southern Transm.	☑		We do not feel there is a reliability need for modifying the standard. However, we do agree certain modifications are needed to clarify procedural issues such as the amount of time allowed for taking corrective action when items are found to be out of compliance.
Response: The team concurs that the technical elements are generally adequate and there is no reliability need to revise the standard. However all NERC standards must be updated to comply with new procedural requirements and inclusion of compliance elements. The Standard DT will address the issues raised in the FERC's March 16, 2007 Order 693 - Mandatory Reliability Standards for the Bulk Power System. The SDT shall consider producing a white paper to aid in clarifying the intent of the standard.			
TVA	☑		The primary needs for mocdifications to this standard are in areas to address clarifications and formatting not reliability related issues.
Response: The SAR DT agrees and thanks you for the comment.			

2. **If you are a transmission owner, have you been provided a list from a Regional Entity (formerly RRO) of sub 200 kV critical transmission lines that must comply with FAC-003-1?**

Summary Consideration: During the March 2007 SAR DT meeting, the FERC indicated they had not been presented any evidence with respect to Regional Entity (RE) critical line determinations and asked whether such lists existed. This question was posed to ascertain whether REs have determined which lines below 200 kV are critical.

Some commenters reported that their RE (SERC, FRCC, RFC) have determined there are no critical transmission lines that are under 200 kV. Some commenters (NGrid, NU, HydroOne, HQT) indicated that a list was not provided by their RE (NPCC). A commenter (MRO) noted that a list was submitted to NERC. A commenter responded that their RE (WECC) has provided such a list. On the basis of this informal poll, the SAR DT's assessment is that further specificity may be needed to aid in identifying which <200kV transmission lines should come under the purview of this standard in an attempt to standardize this criteria.. The SDT shall take under consideration other applicability parameter criteria in addition to various stakeholder proposals.

Question #2			
Commenter	**Yes**	**No**	**Comment**
IRC SRC			n/a
NYISO			n/a
Baltimore Gas & Electric		☑	The reason that we do not have a list of critical lines from the RRO may be that we do not have any lines that fit the criteria.
Response: The SAR DT thanks you for your response.			
CECD		☑	SERC does not currently have any sub 200 kV critical transmission lines.
Response: The SAR DT thanks you for your response.			
CenterPoint Energy		☑	
Central Maine Power		☑	The "Northeast Power Coordinating Council Facilities Notification List" may not be the correct list to be used for this standard. FAC- 003-1 should set a clear expectation the each Regional Entity will provide their transmission owners a list of critical lines including any that may be less that 200KV. Will provide list once released from NPCC.
Response: The SAR DT thanks you for your response.			
Dominion		☑	
Duke Energy		☑	The SERC region has not identified any lines below 200kV to be critical to the electrical system in the region. Since no lines have been identified as critical to the region, no list has been provided to Transmission Owners.
Response: The SAR DT thanks you for your response.			
HQT		☑	We consider that it should be the Planning Coordinator role to determine the sub 200kV critical transmission lines and even for any transmission lines irrelevant of voltage level.

Question #2			
Commenter	**Yes**	**No**	**Comment**
			For that, it should follow an impact based methodology such as the one used in NPCC.
Response: The SAR DT thanks you for your response.			
Hydro One Networks		☑	
Manitoba Hydro		☑	
MRO		☑	The MRO We have not generated a list or criteria yet. We have submitted a draft criteria to NERC
Response: The SAR DT thanks you for your response.			
National Grid		☑	The Reliability Entity has not provided a list of sub 200 kV lines subject to compliance with FAC-003-1. The Standard became effective in February 2007, just 3 months ago. Having no list today should not imply that the RE or the Standard has failed in any way. National Grid suggests that a revised Standard should direct the RE to produce a list of "sub 200 kV critical transmission lines" within 6 to 12 months of adoption.
Response: The standard DT will review applicability parameters of this standard, taking into account the comments from stakeholders such as NU, National Grid, Manitoba Hydro, First Energy, and others.			
Northeast Utilities		☑	The Reliability Entity has not provided a list of facilities covered under FAC-003-1. This is not a fault of the RE as there has been no direction provided as to what factors or charateristics are required for sub-200kV lines to be included under the Standard. It is our position that the factors that will be used to develop the list of sub-200kV faciltities to be covered by the Standard be developed at the national level (NERC) and adopted by all RE's for consistency.
Response: The standard DT will review applicability parameters of this standard, taking into account the comments from stakeholders such as NU, National Grid, Manitoba Hydro, First Energy, and others.			
PGN		☑	The SERC and FRCC regions have not identified any lines below 200kV to be critical to the electrical system in the region. Since no lines have been identified as critical to the region, no list has been provided to Progress Energy Carolinas and Progress Energy Florida. (Please note our comments on this issue in question #4.)
Response: The SAR DT thanks you for your response.			
SERC VMS		☑	The SERC region has not identified any lines below 200kV to be critical to the electrical system in the region. Since no lines have been identified as critical to the region, no list has been provided to Transmission Owners. (Please note the subcommittee's comments on this issue in question #4.)
Response: The SAR DT thanks you for your response.			
TVA		☑	We detemined that there are no TVA lines below 200kv that must comply to this standard due to their criticial needs in SERC.

Question #2			
Commenter	**Yes**	**No**	**Comment**
Response: The SAR DT thanks you for your response.			
VELCO		☑	VELCO has not been provided a specific list of critical lines below 200 kV from the RE that need to be in compliance with FAC-003-1. VELCO suggests changing the wording in the standard to identify those lines affected as 200 kV and great or those defined as Bulk Power System facilities.
Response: The standard DT will review applicability parameters of this standard, taking into account the comments from stakeholders such as NU, National Grid, Manitoba Hydro, First Energy, and others.			
Entergy Corp.	☑		Yes, the Reliability Entity (SERC) has performed its duty in evaluating our transmission system. SERC has confirmed that Entergy has no lines operating below 200kV that are critical to system reliability. Entergy has received its "list," but the list is blank. With respect to applicability, it is inappropriate to set a blunt voltage level criterion for determining which transmission lines are critical to bulk system reliability. There is no basis in engineering or in fact for voltage-based categories of applicability. Many lines operating at 200kV and higher essentially serve only local load, and there may in fact be some lines operating below 200kV where the standard should be applied. Many lines of all voltages are redundant and do not even impact local load during an outage. Therefore, the voltage criterion is overly broad. To support this statement, Entergy supplies the following facts: First, during the aftermath of Hurricanes Katrina and Rita, Entergy had (59) 230kV and 500kV lines out of service simultaneously. Additionally, Entergy had (85) 115kV and 161kV lines out of service simultaneously. During the aftermath of Hurricane Rita, Entergy had (41) 230kV and 500kV lines out of service simultaneously. Additionally, Entergy had (124) 115kV and 161kV lines out of service simultaneously. Dispite this overwhelming combination of simultaneous outages, no system-wide cascading blackout was initiated. Only local load was lost during restoration. This illustrates that Standard FAC-003-1, as it currently stands placing so much focus and penalty on even single-contingency outages, is overbroad, arbitrary and capricious. Second, each year the Entergy transmission system (like all other large electric utilities) suffers numerous outages from a great number of different sources: material defects, rot and decay, animal damage, human damage, extreme wind, lightning and, vegetation. Over the years 2001 through 2006, 927 transmission lines suffered 5,688 outages from a variety of sources. Vegetation outages accounted for 7.14% of those outages. Each

Question #2			
Commenter	**Yes**	**No**	**Comment**
			utility is unique, but these numbers are not unusual for a transmission system comprising 15,000 miles of line. Dispite this large number of outages, no cascading system black out has been intiated. Finally, Entergy has had as many as 17 transmission lines outaged from a single tornado event without even losing service to local load. Standard FAC-003-1 assigns too much risk to outages in general, and too mush risk to vegetation outages in particular. NERC and the regional reliability entities should define performance criteria that specifically define certain contingencies and certain undesireable outcomes that would classify a line as truly critical to bulk system reliability. The modeling software necessary to do this is readily available and already in use today by the Reliability Entities and their subject utilities. If FERC has concerns about potentially devistating (albeit rare) combinations of multiple simultaneous line outage contingencies, the REs can define strict criteria for multiple contingencies. With respect to lines that result in IROLs and SOLs, these lines can also be identified with specificity, without resorting to blunt voltage distinctions. Defining system-critical lines too broadly is actually detrimental to FERC's reliability goals. It dilutes the resources available to maintain reliability on those lines that truly affect system reliability. Utilities should employ a more focused and intelligent approach to targeted reliability. Such an approach would have benefits to the users of the transmission system and to the ratepayers that pay for it.
Response: The standard DT will review applicability parameters of this standard, taking into account the comments from stakeholders such as yourself and others.			
Florida Power & Light	☑		
PGE	☑		Provided from WECC
Response: The SAR DT thanks you for your response.			
AEP	☑	☑	Of the three regions in which AEP has transmission facilities, only one RE has provided a listing of sub-200 kV facilities of what we consider applicable under this standard.
Response: The SAR DT thanks you for your response.			
FirstEnergy Corp.	☑	☑	ReliabilityFirst, the Reliability Entity (formerly the RRO) was requested to provide a list of lines below 200 kV deemed as critical transmission lines that must comply with FAC-003-01. ReliabilityFirst responded "there are no lines below 200kV deemed as critical

Question #2			
Commenter	**Yes**	**No**	**Comment**
			infrastructure".
Response: The SAR DT thanks you for your response.			
Southern Transm.	☑	☑	We are not really sure how to answer this question. The Regional Entity has not sent us a list, but they have advised us that we do not have any sub 200 kv critical transmisison lines that must comply with FAC-003-1.
Response: The SAR DT thanks you for your response.			

3. If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.

Summary Consideration: This question was posed to poll transmission owners with respect to determination of Clearance 1 and Clearance 2 requirements. This information was sought to obtain examples of how industry members determine Clearance 1 since it is a qualitative requirement. Clearance 2 information was sought to evaluate the application of components of IEEE 516.

Of the 15 respondents to this poll question, some provided summary methodology for determining their Clearance 1 and Clearance 2, others have indicated that a methodology exists and is available upon request. On the basis of these responses to the poll question, the SDT shall consider reviewing IEEE 516 components to affirm their suitability in this standard and this information can assist in a white paper.

Question #3			
Commenter	**Yes**	**No**	**Comment**
IRC SRC			n/a
NYISO			n/a
SERC VMS			This question does not apply to the SERC EC Vegetation Management Subcommittee.
Response: The SAR DT thanks you for your response.			
Baltimore Gas & Electric		☑	
Central Maine Power		☑	The clearance 2 was taken directly from IEEE Table 516 – 2003. Clearance 1 is based on "Appendix C – ISO New England Right of way Vegetation Management Standard".
Response: The SAR DT thanks you for your response.			
Florida Power & Light		☑	
National Grid		☑	Detailed methodology is not attached. In summary, National Grid used Table 5 IEEE Section 516 for determing clearance 2. These data for each voltage class were rounded to the next higher whole number. Clearance 1 was determined by adding the clearance 2 distance, conductor sag distance, and anticipated tree growth over the maintenance cycle.
Response: The SAR DT thanks you for your response.			
PGN		☑	Progress Energy has an individual on the Drafting Team and will share the Progress Energy Florida clearance Tables with the team.
Response: The SAR DT thanks you for your response.			
VELCO		☑	VELCO has defined Clearance 1 as the maximum allowed vegetation heights (12ft high) at time of maintenance. This maximum height has evolved from experience with regional

Question #3			
Commenter	**Yes**	**No**	**Comment**
			growth rates and other factors. VELCO's Clearance 2 is determined by the New England ISO's Operating Procedure 3, which is slightly more stringent than IEEE 516.
Response: The SAR DT thanks you for your response.			
AEP	☑		For Clearance 1, AEP has chosen to use the minimum approach distances set forth in ANSI Tree Care Standard Z133.1 (rev. October 2000) for persons other than qualified line-clearance arborists and qualified line-clearance arborist trainees. For Clearance 2, AEP utilizes the Z133.1 minimum approach distances for qualified line clearance arborists and qualified line-clearance arborist trainees.
Response: The SAR DT thanks you for your response.			
CenterPoint Energy	☑		CenterPoint Energy has developed a methodology to determine clearance 1 and clearance 2 as described in FAC-003-1 R1.2.1 and R1.2.2. This methodology is included in a document titled "Specification for Transmission Vegetation Management Program" dated February 2007. Section 5.1 of that document covers NERC Clearance 1, and Section 5.2 covers NERC Clearance 2. Text and Tables from both Sections 5.1 and 5.2 are shown below: 5.1 NERC CLEARANCE 1 5.1.1 The appropriate clearance to conductors at the time of vegetation management work is established as Clearance 1 in accordance with NERC Standard FAC-003-1 Requirement R1.2.1. 5.1.2 Clearance 1 is determined by considering transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, the effects of wind velocities on conductor sway, and the anticipated average growth rate of the prevalent tree species within the Company's service area over a 5-year period. 5.1.2.1 The minimum clearance distance of IEEE Standard 516-2003 Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap, is a component of Clearance 1. 5.1.3 Table 5.1 contains the horizontal clearance components and nominal values for Clearance 1, and Table 5.2 contains the vertical clearance components and nominal values for Clearance 1. Table 5.1

<table>
<tr><th colspan="4">Question #3</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td>
NERC Clearance 1: Horizontal Clearance, feet
Horizontal Clearance Component, Nominal Voltage p-p
<table>
<tr><th></th><th>69kV</th><th>138kV</th><th>345kV</th></tr>
<tr><td>Electrical Clearance (1)</td><td>2.46</td><td>2.95</td><td>4.40</td></tr>
<tr><td>Average 5-Year Horizontal Tree Growth</td><td>12.00</td><td>12.00</td><td>12.00</td></tr>
<tr><td>Average Mid-span Conductor Sway (2)</td><td>5.98</td><td>8.13</td><td>10.04</td></tr>
<tr><td>Total</td><td>20.44</td><td>23.08</td><td>26.44</td></tr>
<tr><td>Nominal Horizontal Value (3)</td><td>20</td><td>23</td><td>26</td></tr>
</table>
(1) Based on IEEE 516-2003 Table 5 for 69kV & 138kV and Table 7 for 345kV
(2) Based on NESC C2-2007 Rule 233A(1)
(3) May be reduced for site specific tree species or conductor span configuration but not less than Clearance 2.

Table 5.2
NERC Clearance 1: Vertical Clearance, feet
Vertical Clearance Component, Nominal Voltage p-p
<table>
<tr><th></th><th>69kV</th><th>138kV</th><th>345kV</th></tr>
<tr><td>Electrical Clearance (1)</td><td>2.46</td><td>2.95</td><td>4.40</td></tr>
<tr><td>Average 5-Year Vertical Tree Growth</td><td>15.75</td><td>15.75</td><td>15.75</td></tr>
<tr><td>Average Conductor Final Sag Increase (2)</td><td>7.52</td><td>9.01</td><td>10.24</td></tr>
<tr><td>Total</td><td>25.73</td><td>27.71</td><td>30.39</td></tr>
<tr><td>Nominal Vertical Value (3)</td><td>26</td><td>28</td><td>30</td></tr>
</table>
</td></tr>
</table>

Question #3			
Commenter	**Yes**	**No**	**Comment**
			(1) Based on IEEE 516-2003 Table 5 for 69kV & 138kV and Table 7 for 345kV (2) Based on NESC C2-2007 Rule 233A(1) (3) May be reduced for site specific tree species or conductor span configuration but not less than Clearance 2. 5.2 NERC CLEARANCE 2 5.2.1 The minimum radial clearance to prevent flashover between vegetation and conductors is established as Clearance 2 in accordance with NERC Standard FAC-003-1 Requirement R1.2.2. 5.2.2 Clearance 2 is determined by considering transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Clearance 2 is a radial clearance, so the vertical component and the horizontal component are both calculated, and the largest clearance is selected as the prevailing clearance for Clearance 2. 5.2.2.1 The minimum clearance distance of IEEE Standard 516-2003 Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap, is a component of Clearance 2. 5.2.3 Table 5.3 contains the horizontal clearance component, Table 5.4 contains the vertical clearance component, and Table 5.5 contains the prevailing nominal values for Clearance 2. Table 5.3 Horizontal Clearance Component, feet Horizontal Clearance Component, Nominal Voltage p-p <table><tr><td></td><td>69kV</td><td>138kV</td><td>345kV</td></tr><tr><td>Electrical Clearance (1)</td><td>2.46</td><td>2.95</td><td>4.40</td></tr><tr><td>Average Mid-span Conductor Sway (2)</td><td>5.98</td><td>8.13</td><td>10.04</td></tr></table>

Question #3			
Commenter	**Yes**	**No**	**Comment**
			Total 8.44 11.08 14.44 Nominal Horizontal Value (3) 8 11 14 (1) Based on IEEE 516-2003 Table 5 for 69kV & 138kV and Table 7 for 345kV (2) Based on NESC C2-2007 Rule 233A(1) (3) May be reduced for site specific tree species or conductor span configuration but not less than Clearance 2. Table 5.4 Vertical Clearance Component, feet Vertical Clearance Component, Nominal Voltage p-p 69kV 138kV 345kV Electrical Clearance (1) 2.46 2.95 4.40 Average Conductor Final Sag Increase (2) 7.52 9.01 10.24 Total 9.98 11.96 14.64 Nominal Vertical Value (3) 10 12 15 (1) Based on IEEE 516-2003 Table 5 for 69kV & 138kV and Table 7 for 345kV (2) Based on NESC C2-2007 Rule 233A(1) (3) May be reduced for site specific tree species or conductor span configuration but not less than Clearance 2. Table 5.5 NERC Clearance 2: Minimum Radial Clearance to Prevent Flashover, feet Nominal Voltage p-p 69kV 138kV 345kV 10 12 15

Question #3			
Commenter	**Yes**	**No**	**Comment**
Response: The SAR DT thanks you for your response.			
Entergy Corp.	☑		Entergy defines four sets of clearances for vegetation approach to transmission lines. The first set of clearances is the Vegetation Pruning Distance. This is the clearance to be achieved at the time of vegetation management work which vegetation management employees and contractors complete as part of this program. This distance varies with each line, but is set to be the EDGE OF ROW in each case. (This clearance is referred to as "Clearance 1" in the NERC Vegetation standard FAC-003-1, Cf B.R1.2.1). The second set of clearances is the Vegetation Growth Alert Distance. This is the approach distance that triggers an alert to the Asset Management vegetation management employees that vegetation maintenance is required. Vegetation spotted on an aerial inspection that encroaches upon this clearance is noted on the inspection for future scheduling of pruning. The third set of clearances is the Minimum Energized Pruning Distance. This is the minimum approach distance vegetation can have to energized transmission lines and still be pruned without an outage on the energized transmission line, in accordance with OSHA safety guidelines. Any vegetation that encroaches on this minimum distance must be pruned, and must be pruned during an outage on the associated transmission line. The fourth set of clearances is the Minimum Vegetation Approach Distance. This is the absolute minimum radial approach distance to prevent flashover between vegetation and overhead ungrounded supply conductors. Under this program, vegetation should never encroach these minimum approach distances. Vegetation must be pruned prior to reaching this distance and must be pruned with an outage on the transmission line. (This distance is referred to as "Clearance 2" in the NERC vegetation standard, FAC-003-1, Cf B.R1.2.2.) These clearance distances are based upon those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (Guide for Maintenance Methods on Energized Power Lines) and as specified in Table 5. Under this program, vegetation can encroach the Vegetation Growth Alert Distance and the Minimum Energized Pruning Distance, but it shall not encroach upon the Minimum Vegetation Approach Distance.
Response: The SAR DT thanks you for your response.			

Question #3			
Commenter	**Yes**	**No**	**Comment**
FirstEnergy Corp.	☑		For R1.2.1 (Clearance 1), FirstEnergy used our existing specification requirement "for minimum clearance to be achieved at locations with an easement or other restriction" to define the minimum acceptable clearance. For R1.2.2 (Clearance 2), FirstEnergy uses the IEEE 516-2003 standard as the minimum as referenced in FAC-003-01. This is the minimum clearance under all operating conditions. FirstEnergy believes this is an appropriate definition.
Response: The SAR DT thanks you for your response.			
HQT	☑		HQT clearance methodology is not specifically based on the value specified in Clearance 1 and Clearance 2. HQT TVMP is such organized that vegetation management work minimize costs for line clearing and brush control while preventing outages from vegetation cause. As such, staff qualifications required to work near energized facilities are less than under the absolute minimum as stipulated in IEEE 516-2003, and in most cases, the work is less labour and equipment intensive. However clearances are never less than the absolute minimum stipulated in FAC-003-1 (R1.2.2). The above provides the basic approach used at HQT. If the Standard Drafting Team would like a copy of the HQT approach and methodology, this could be provided.
Response: The SAR DT thanks you for your response.			
Hydro One Networks	☑		Hydro One clearance standards are based on the Ontario Health and Safety Act (OHSA) clearances rather than the absolute minimum specified in Clearance 2. OHSA clearances at time of work minimize costs for line clearing and brush control. By maintaining OHSA clearances during normal working conditions, staff qualifications required to work near energized facilities are less than under the absolute minimum as stipulated in IEEE 515-3003, and in most cases, the work is less labour and equipment intensive. As part of work planning, qualified staff determine the amount of vegetation that has to be removed to achieve OHSA clearances at the time of the next scheduled work. As well, provisions are built into the clearances at time of work to account for conductor and tree movement during adverse weather conditions. The objective is to provide OHSA clearances under adverse conditions, but these are not always achieved, however clearances are never less than the absolute minimum stipulated in FAC-003-1. The above provides a description of our planning process. If the Standard Drafting Team would like a copy of the Hydro One standard, this can be provided.
Response: The SAR DT thanks you for your response.			

Question #3			
Commenter	**Yes**	**No**	**Comment**
Manitoba Hydro	☑		Clearance 1 was developed based on the limits of approach for non-qualified people (public). At a minimum, we would clear beyond this distance during vegetation control activities. Our cycle times and management approach are adjusted for this distance, taking into account growth rates. The values will vary depending on voltage class. Clearance 2 is based on internal design standards that take into account our understanding of switching surge values for our system. The values used are more conservative than IEEE 516-2003.
Response: The SAR DT thanks you for your response.			
MRO	☑		n/a
Northeast Utilities	☑		The methodology for determining clearance 2 is based on the requirements of FAC-003-1. The IEEE Section 516 has been considered the base minimum limits for clearances as provided under FAC-003-1 R.1.2.2. Clearances used for R.1.2.1 on the NU Transmission System comply with the requirements of ISO-NE Operating Procedure OP-3, that provides clearance levels required at the time of vegetation trimming or clearing under the various transmission voltages.
Response: The SAR DT thanks you for your response.			
PGE	☑		Will be provided to the SARDT in a separate attachment[TH1].
Response: The SAR DT thanks you for your response.			
Southern Transm.	☑		IEEE 516-2003, Section 4.2.2.3 was adopted as the minimum allowable distance for Clearance 2, with the expectation that work would normally occur prior to Clearance 2 reaching the minimum allowable distance. Clearance 1 was determined by using the Clearance 2 value and adding a growth buffer. Sagging of conductors and their movement in wind was then considered to ensure the growth buffer is adequate.
Response: The SAR DT thanks you for your response.			
TVA	☑		We utilize a clearance 2 based on IEEE 516 2003 Table 5 criteria. Our Clearance 1 is a greater amount to allow for growth between clearing and next inspection or clearance activities. We will provide our tables is requested.
Response: The SAR DT thanks you for your response.			

4. **Are there any other comments regarding the standard, its possible modifications or the SAR?**

Summary Consideration:
The comments were mixed with regard to:
- Whether reporting of Category 3 outages are necessary.

Most that commented agreed that:
- The 200kV applicability threshold could be clarified and the SAR DT deemed a review of applicability parameters is desirable.
- A consistent approach to both federal and non federal lands is desirable.
- A review of the definition of ROW is desirable.
- Components of the IEEE 516 standard are suitable.
- The exclusion of major disaster related events is appropriate.
- The inclusion of compliance elements and other procedural updates of the standard are needed.
- The development of a technical white paper is desirable.
- The standard DT should review the need for Requirement R4.

On the whole, the comments are supportive of the SAR as written and the SAR DT have made no changes to the second draft of the request.

Question #4			
Commenter	**Yes**	**No**	**Comment**
CenterPoint Energy		☑	
Manitoba Hydro		☑	
PSC SC		☑	
Southern Transm.		☑	We appreciate the efforts of the SAR Drafting Team.
AEP	☑		The SAR directs the SDT to collect and analyze outage data as part of an effort to define clearances for transmission lines on federal and non-federal lands. AEP believes that the analysis of outage data will be meaningless and unproductive. The SAR directive presupposes a cause-and-effect relationship between vegetation-related outages and federal/non-federal land status. On the contrary, AEP believes that vegetation-related data is more indicative of the effectiveness of the utility's VM program, in spite of onerous and inordinately expensive measures required on federal lands.
Response: The standard DT looks to receive the results of the ERO analysis and use it in developing the standard.			

Question #4			
Commenter	**Yes**	**No**	**Comment**
Ameren	☑		Ameren does not agree that each of 11 items listed in the SAR are necessary to improve reliability. The following comments are offered for each of the 11 items identified in the SAR detail description: 1. Standard Applicability: Ameren disagrees with revising the 200 kV threshold for determining facilities subject to this standard. Extending the requirements to lines other than those >200kV will dilute the focus on those lines that impact grid reliability and shift attention to facilities, <200kV. Utilities generally have an incentive to maintain reliability on lines less than 200kV. State commissions and customer expectations for reliable service provide this incentive. While many facilities above 200kV directly support customer load, transmission lines below 200kV primarily support customer load, and interruptions to those facilities reduces load on the grid. The majority of transmission facilities below 200 kV also have significantly different design/construction/operating characteristics and have not been cited as impacting bulk power system reliability. For example, the Final Report on the August 14, 2003 Blackout in the United states and Canada: Causes and Recommendations April 2004 by the U.S.-Canada Power System Outage Task Force and all referenced major blackouts (pages 103-115) in that report, cited only outages which involved vegetation at line voltages above 200kV. Generally applying requirements that are appropriate for >200kV lines to lines less than 200kV will result in significant documentation and reporting of items such as restrictions, mitigation plans, off right-of-way vegetation-related outage investigation/ information and other issues, all of which dilutes the focus on lines that directly impact bulk power system reliability. Revising the standard to use general criteria or broad language for defining "Bulk Power System" transmission lines covered by the standard is a “one size fits all” approach. If that approach were taken, the standard would cover a significant number of transmission lines that have no direct impact on bulk power system reliability under standard planning/operating conditions, resulting in a significant cost burden for electric customers without improving “grid” reliability. Ameren believes that the applicability provision of the standard should focus attention of the standard only on the transmission lines below 200kV that directly impact “Bulk Power System” reliability, as the current version requires.

Question #4			
Commenter	**Yes**	**No**	**Comment**
			Ameren recognizes some validity in the Commission's concern; Ameren recommends that the applicability provision of this standard should be revised only if existing system design, planning or operating reliability criteria and parameters are considered as a basis for defining the applicability of the standard. Ameren recommends each Regional Entity (RE) determine applicability of FAC-003 to those lines within the region that are between 100kV and 200KV, if, and only if, they are identified as operationally significant elements of Interconnection Reliability Operating Limits ("IROLs"). That is, any facility below 200kV that by itself would cause an Interconnected Reliability Limit Violation should the facility be outaged. 2. Issue of Clearances (Federal vs Non-Federal Lands): FAC-003-1 presently requires the transmission owner (TO) "identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway." The intent of this requirement is to ensure adequate clearances to prevent vegetation related outages. Ameren believes that only the TO has the technical information required to determine the clearances that are necessary at the time of VM work and that any "federal lands exemption" to clearances will result in inadequate clearances for the existing conditions. Consistency in application of the TO's clearance requirements, not exceptions, is the only assurance in providing a uniform and reliable electrical system to meet the nation's current and future energy demands. Any exception for a case by case clearance approach to determine vegetation management activities/clearances on Federal lands will continue to drive inconsistency and/or delays associated with vegetation management decisions being driven by diverse vegetation management practices/beliefs and staff changes at the local level of Federal agencies. Vegetation-related outages have occurred on Federal lands as a result of this case by case approach, and if "Bulk Power Transmission System" lines continue to be addressed on a "case by case" basis on National Forest Service (or any other Federal lands), those lines will potentially be subject to a higher risk for vegetation-related outages, resulting in reduced reliability for the "Bulk Power System". Ameren believes that reliability of the "Bulk Power System" should have the same focus on Federal and private lands and that the EEI MOU with federal agencies is the

Question #4			
Commenter	**Yes**	**No**	**Comment**
			appropriate vehicle for TO's to identify clearance variances on Ferderal lands, not exemption language in the standard. The standard should not be used as a mechanism by federal agencies to impose variances to proven vegetation management practices and clearances. 3. Defining Right-of-Way: Ameren agrees that it is appropriate to further address the definition of "right-of-way". Corridor widths beyond design clearance requirements have been acquired for a variety of reasons in the past; future use, property line buffers, etc. Vegetation in those areas that would normally fall outside of the area necessary for operation of the facility should not be considered or treated different than vegetation that is outside of a defined easement/permit area that is designed for the reliable operation of an existing single line corridor. 4. IEEE Standard for Minimum Clearances: Ameren disagrees with objections to the use of the IEEE 516-2003 clearance as the minimum acceptable distances for "Clearance 2". The IEEE 516-2003 tables are appropriate for defining the minimum acceptable clearances to prevent flashover between conductors and vegetation under all rated electrical operating conditions. FERC staff references ANSI Z-133 which is a safety standard that addresses worker safety as well as the safety of the general public. As such, the purpose of ANSI Z-133 is to address worker safety and is not focused on transmission line reliability, which is the purpose of FAC-003-1. OSHA, NESC and other related safety standards have clearances in excess of IEEE 516-2003. Those clearances are clearly focused on safety issues and will still apply to other aspects of design and operation of electric facilities (such as public and worker safety) but are not appropriate to be referenced in a vegetation management reliability standard. 5/6/7. Procedural Items: Ameren agrees that the procedural items related to formatting RRO references and additional compliance elements should be addressed by the standard drafting team. 8. Technical Reference Materials:

Question #4			
Commenter	**Yes**	**No**	**Comment**
			Ameren agrees that a "white paper" that defines the technical basis for the standard is appropriate to avoid the potential for differences in interpretation of the standard's requirements during the various region's audit processes. 9. Category 3 Outages: Since the right to control off right-of-way vegetation is generally beyond control of the transmission owner Ameren believes that the reporting of category 3 outages should be removed from the requirements. 10. Requirement R4: Ameren believes that requirement R4 should be deleted from the standard, based on the ERO formation and the process for delegation of authority to the regional entities. 11. Reporting Exemptions: Ameren believes that the reporting requirement exemptions for natural disasters should include all categories of outages. It would, for example, be difficult, without delaying restoration efforts, to determine if the vegetation from high winds, hurricanes, tornadoes, etc. is from on or off the "right-of-way".

Response:

1. The standard DT will review applicability parameters of this standard, taking into account the comments from stakeholders such as NU, National Grid, Manitoba Hydro, First Energy, and others.
2. The SAR DT concurs with the commenter with respect to applying this standard to Federal and non-Federal lands. The standard DT will evaluate the suitability of a case-by-case approach.
3. The standard DT will review the definition of ROW.
4. The SAR DT agrees with the commenter and recognizes that sections of IEEE 516 standard pertaining to minimum air insulation distances are applicable in determining minimum vegetation clearances to prevent flashovers.
5. NERC standards must be updated to comply with new procedural requirements and must include compliance elements.
6. See #5
7. See #5
8. The SDT shall consider producing a white paper to aid in clarifying the intent of the standard.
9. The SAR indicates that the Standard Drafting Team will review reporting criteria for Category 3 outages and will review the reporting requirement of Category 3 outages in R.3 and R.4.

Question #4			
Commenter	**Yes**	**No**	**Comment**
10. The standard DT will consider deletion of R.4. 11. The standard DT will review the reporting exemptions to include all category outages under major disasters in Requirement R3.2.			
Baltimore Gas & Electric	☑		We completely disagree with the proposal to eliminate reporting or off-right-of-way tree outages. In reality, off-R/W outages can cause many of the same problems that on R/W outages do if they were to occur at the most inappropriate time. Granted that they typically do not occur at times of peak load, but they could. Moreover, many off-R/W tree outages are preventable and should be addressed before they occur.
Response: The SAR indicates that the Standard Drafting Team will review reporting criteria for Category 3 outages and will review the reporting requirement of Category 3 outages in R.3 and R.4.			
CECD	☑		CECD supports continuing to use the 200kV threshold for determining applicability of vegetation management criteria. If the standard is deemed to apply to lower voltages these should only be critical lower voltage transmission facilities as determined by the Regional Entities's. CECD would also encourage the drafting team to clarify that the Vegetation Management standards are not applicable to generator interconnection facilities. In the registration process due to the NERC functional definitions, Generation Owners/Operators are required to register as Transmission Owners/Operators because of step-up transformers and other associated interconnection equipment that was not intended to be subject to the Vegetation Management program.
Response: The standard DT will review applicability parameters of this standard, taking into account the comments from stakeholders such as NU, National Grid, Manitoba Hydro, First Energy, and others. As a registered transmission owner this standard is applicable. Registration matters should be referred to the NERC organization certification program and the related regional entity.			
Central Maine Power	☑		The standard FAC-003-1 is intended to create a frame work that will ensure a uniform level of reliability and at the same time must allow transmission owners to meet this objective using efficient and cost effective programs. To this end utilities must have the ability to implement "Clearance 1" distances consistently throughout their service areas. The standard should remain focused only on 200 KV and above lines or lines listed as critical by the Regional Entity. Inspection cycles are sufficient as listed the current version and allow flexibility to meet local variability in growth rates and other conditions. Concerns with inspection cycle length can be addressed in the compliance area.

Question #4			
Commenter	**Yes**	**No**	**Comment**
Response: The SAR DT thanks you for your comments. The standard DT will review applicability parameters of this standard, taking into account the comments from stakeholders such as yourself and others. The FERC is no longer indicating a need to develop a requirement for a minimum inspection cycle (March 16, 2007 Order 693) and stakeholders indicated they did not support this change, so it was removed from the SAR.			
Dominion	☑		In response to Stakeholder item #11, we do not support exempting Category 1 or Category 2 events that occur during natural disasters.
Response: A majority of the industry stakeholder comments support natural disaster exemptions.			
Duke Energy	☑		Regarding the Order 693 items, the applicability provision of the standard should focus attention of the standard only on the transmission lines 200kV and above, and those lines below 200kV that directly impact "Bulk Power System" reliability, as the current version of FAC-003 requires. Each Regional Entity (RE) must determine applicability of FAC-003 to those lines within the region that are less than 200kV. For example, transmission lines below 200kV should be considered within the scope of FAC-003 if they are identified as operationally significant elements of Interconnection Reliability Operating Limits ("IROLs"); i.e. an outage of the facility would cause an Interconnection Reliability Limit Violation. The Standard DT should address the issue of the necessity of maintaining consistent clearances for lines on both federal and non-federal lands. We agree with the use of the IEEE 516-2003 standard for for defining the minimum acceptable clearances to prevent flashover between conductors and vegetation under all rated electrical operating conditions. We believe that the reporting requirement exemptions for natural disasters should include all categories of outages.
Response: The standard DT will review applicability parameters of this standard, taking into account the comments from stakeholders such as NU, National Grid, Manitoba Hydro, First Energy, and others. The SAR DT concurs with the commenter with respect to applying this standard to Federal and non-Federal lands. The standard DT will evaluate the suitability of a case-by-case approach. The SAR DT agrees with the commenter and recognizes that sections of IEEE 516 standard pertaining to minimum air insulation distances are applicable in determining minimum vegetation clearances to prevent flashovers.			

Question #4			
Commenter	**Yes**	**No**	**Comment**
The standard DT will review the reporting exemptions to include all category outages under major disasters in Requirement R3.2.			
Entergy Corp.	☑		The policy to increase sanctions based on a finding of an "intentional economic decision to violate the standard" is ill-concieved: 1. Every transmission line outage that has ever occured could have been avoided if more money had been spent on SOMETHING, SOMWHERE. 2. No utility has an unlimited budget, so decisions based on risk, cost and benefit are made every day. 3. After the outage, the localized initiating cause will appear so trivial and inexpensive that it would seem that it could easily have been fixed in advance. 4. Therefore, reviewers could conclude that EVERY outage (a defacto violation of the standard), is the result of an "economic decision to violate the standard." Economic choices are a necessary and natural part of doing business, and do not necessarily imply the existence of malicious motives or wrong-doing. The current policy is going to create unnecessary costs to ratepayers, even to avoid inconsequential outages.
Response: The compliance sanctions guideline addresses the matter of willful noncompliance. Refer to the Compliance program with respect to this issue. However the standard DT and Compliance Elements DT will review and assign Violation Severity Levels when modifying FAC-003-1.			
FirstEnergy Corp.	☑		The definition of Right-Of-Way requires modification to clarify it is the width required by engineering to operate the line. This may or may not be the legal Right-of-Way. (See previously submitted comments submitted by FE in Feb 2007 for more details).
Response: The standard DT will review the definition of ROW.			
Florida Power & Light	☑		For the record FPL re-emphasize its comments from the previous FAC 003-1 SAR. Requirement 3.2 exempts reporting of outages from outside the ROW when natural disasters such as tornados or hurricanes occur. Our experience with numerous hurricanes indicates that all outages during these types of events should be exempt. The focus in these situations is to get the lines back in service and restore customers. There is insufficient manpower to adequately complete the forensics necessary to determine an accurate root cause. It is not uncommon to find vegetation debris in the lines or downed trees on the ROW in this situation. In most cases it is not possible to determine the original location of these trees.

Question #4			
Commenter	**Yes**	**No**	**Comment**
			In the compliance section of the document a transmission owner becomes non compliant with a single category 1 or 2 outage. This occurs regardless of the circumstances. A non compliant penalty for a single outage in a situation where no customers were affected and the system could not have been compromised is not reasonable. It is also not an indicator of a poorly maintained system. We agree that several Category 1 or 2 interruptions could be an indicator of neglect but one is not. We recommend that the compliance section be reviewed with this in mind.
Response: The SDT will review the reporting exemptions to include all category outages under major disasters in Requirement R3.2. The SDT and Compliance Elements DT will review and assign Violation Severity Levels when modifying FAC-003-1. Note that the levels of non-compliance that are in the approved version of FAC-003 will be replaced with violation severity levels.			
HQT	☑		Here are some general comments on the SAR: 1. In the purpose section of the SAR, item 1, we don't understand the substitution of BPS by «electric transmission system»; it seems like there is a will to make the Standards applicable to more than the BPS. It is our understanding that NERC Standards are aimed at the reliability of the BPS. The term BPS should be retained and instead of modifying the SAR to widen the applicability, the Standard itself should be modified to specifically used the term BPS in item A.3. 2. In the detailed description section, item 1, sub-bullet, it is written that: "...the SDT may consider other criteria in determining applicability of the Standard to sub 200 kV lines...". We think that in item 4.3 (Applicability) of the existing Standard, there is already the possibility of applying the Standard to sub 200 kV lines if determined by RRO. This could be reworded by saying: "...as determined by a methodology to define BPS element"; such as the one used by NPCC. 3. We noticed that most Definitions (e.g. RC, IA, PC, RP, TP, TOP, DP, GO, GOP, PSE, MO (not even in the Glossary), LSE) used to described the Reliability Functions in the SAR form, are somewhat different than those used in the Glossary of Terms approved with the Standards deposited at the FERC. For consistency, if the definition needs to be changed, this should be done through the right process, not just casually in the SAR Form. 4. Also, although the title in that same section of the SAR form refers to Reliability Functions, these are in fact the Responsible Entity that performs those functions; maybe a correction in the SAR form would be necessary.

Question #4			
Commenter	**Yes**	**No**	**Comment**
Response: 1. The SAR DT used 'Bulk Electric System' because that is the term defined in the NERC Glossary. 2. The standard DT will review applicability parameters of this standard, taking into account the comments from stakeholders such as NU, National Grid, Manitoba Hydro, First Energy, and others. Furthermore the standard DT will ensure that any new terms defined for use in this standard will also be added to the Glossary of Terms. 3. The standard DT will ensure that any new terms defined for use in this standard will also be added to the Glossary of Terms. the drafting teams were directed to use the definitions for the functional model entities in the version of the Functional Model just approved by the BOT in February, 2007. The glossary will be updated to include the revised definitions for the functional entities. 4. Thanks for the comment.			
Hydro One Networks	☑		We believe from a transmission system perspective, category 3 outages are no different than many of the other types of outages that take place on the system, such as hardware failures, lightning damage and station equipment outages to name a few. It is our understanding that there is no requirement to report these "other" outages, which makes one wonder why the tree related outages that originate off the right of way need to be reported. We are not diminishing the importance of category 3 outages, but from a system cascading perspective, these outages are no more important than other line or station outages, and are fewer in number than the "other" random outages. To initiate system cascading as occurred during August 14, 2003, a number of the random outages would have to coincide to cause a wide spread system event, which in our opinion is a very low probability occurrence. On the other hand, a category 1 outage can occur as a result of any system disturbance should there be deficiencies in clearances to vegetation, as such the importance of category 1 outages is apparent and reporting is appropriate. We support the review concerning the need to report category 3 outages and that the ultimate decision should be based on reporting rules that take into consideration the broader topic of reliability, rather than just vegetation related outages.
Response: The SAR indicates that the Standard Drafting Team will review reporting criteria for Category 3 outages and will review the reporting requirement of Category 3 outages in R.3 and R.4.			
IESO	☑		1. The SAR indicates that a list of critical low voltage transmission lines will be provided to FERC. We do not interpret Order 693 to direct NERC to provide this list. Rather, we interpret that FERC asks for defining a criteria that would include low voltage transmission lines that have impact on Bulk Power System reliability. We do not think the list is required. 2. The SAR indicates: "The standard DT may consider other criteria in determining

Question #4			
Commenter	**Yes**	**No**	**Comment**
			applicability of the standard to sub 200kV lines…" Per Order 693, the criteria is quite clearly stated to be the transmission lines of less than 200 kV that could impact Bulk Power System reliability. We don't feel any other criteria would be necessary. Further, to identify the candidates that meet these criteria, we believe they should be determined by the Reliability Coordinator, similar to the PRC-023 standard, since the RC has the primary responsibility and knowledge of interconnection reliability impact. 3. We do not understand why the SDT considers removing Category 3 incidents? In our view, Category 3 outages are important information for assessing the effectiveness of vegetation program. Since the industry started reporting vegetation related outages about 3 years ago, data collected so far indicates that of a total of 98 reported vegetation outages, 67 of them were category 3 outages. With this high percentage, reporting of Category 3 events should be a must since the associated trends can provide valuable information to the TOs to aid its evaluation of the vegetation management program. 4. The white paper and field tests are a good idea and the SDT should be commended for these, especially the white paper. 5. Item 2 under the FERC Order 693 Items in the Detailed Description Section indicates the SDT will also collection outage data. While we understand that FERC has directed the ERO to collect outage data for transmission outages of lines that cross both federal and non-federal lands, we do not feel that it is the SDT's role to perform this task. We feel that this task should be performed by the ERO line functions or a group separate from the SDT such that the task does not add burden to the SDT which may slow down the standard development process or result in the standard development being driven by unanalyzed data and resulting in erroneous requirements. 6. With respect to reporting exemptions, our position during development of the previous version of this standard was to limit them. We commend the SDT intention to clarify the outage exemptions under major disasters, but to consider including all category outage exemptions in the standard body is too prescriptive and will add to the already extended list. It can end up with a very long list of outage exemptions, thereby reducing the coverage of the standard substantially and defeating its purpose
Response: 1. On the basis of the responses from stakeholders to Question #2 above, the SAR DT's assessment is that further			

Question #4			
Commenter	**Yes**	**No**	**Comment**
specificity may be needed to aid in identifying which <200kV transmission lines should come under the purview of this standard. The SDT shall take under consideration other applicability parameter criteria, various stakeholder proposals including IROL violation potential. 2. See # 1 above. 3. The SAR indicates that the Standard Drafting Team will review reporting criteria for Category 3 outages and will review the reporting requirement of Category 3 outages in R.3 and R.4. 4. The SAR DT thanks you for your comment. 5. The SDT looks to receive the results of the ERO analysis and use it in developing the standard. 6. The SDT will review the reporting exemptions to include all category outages under major disasters in Requirement R3.2.			
IRC SRC	☑		1. The SAR indicates that a list of critical low voltage transmission lines will be provided to FERC. We do not interpret Order 693 to direct NERC to provide this list. Rather, we interpret that FERC asks for defining a criteria that would include low voltage transmission lines that have impact on Bulk Power System reliability. We do not think the list is required. 2. The SAR indicates: "The standard DT may consider other criteria in determining applicability of the standard to sub 200kV lines…" Per Order 693, the criteria is quite clearly stated to be the transmission lines of less than 200 kV that could impact Bulk Power System reliability. We don't feel any other criteria would be necessary. Further, to identify the candidates that meet this criteria, we believe they should be determined by the Reliability Coordinator, similar to the PRC-023 standard, since the RC has the primary responsibility and knowledge of interconnection reliability impact. 3. We do not understand why the SDT considers removing Category 3 incidents? In our view, Category 3 outages are important information for assessing the effectiveness of vegetation program. Since the industry started reporting vegetation related outages about 3 years ago, data collected so far indicates that of a total of 98 reported vegetation outages, 67 of them were category 3 outages. With this high percentage, reporting of Category 3 events should be a must since the associated trends can provide valuable information to the TOs to aid its evaluation of the vegetation management program. 4. The white paper and field tests are a good idea and the SDT should be commended for these, especially the white paper.

Question #4			
Commenter	**Yes**	**No**	**Comment**
			5. Item 2 under the FERC Order 693 Items in the Detailed Description Section indicates the SDT will also collect outage data. While we understand that FERC has directed the ERO to collect outage data for transmission outages of lines that cross both federal and non-federal lands, we do not feel that it is the SDT's role to perform this task. We feel that this task should be performed by the ERO or a group separate from the SDT such that the task does not add burden to the SDT which may slow down the standard development process or result in the standard development being driven by unanalyzed data and resulting in erroneous requirements. 6. With respect to reporting exemptions, our position during development of the previous version of this standard was to limit them. We commend the SDT intention to clarify the outage exemptions under major disasters, but to consider including all category outage exemptions in the standard body is too prescriptive and will add to the already extended list. It can end up with a very long list of outage exemptions, thereby reducing the coverage of the standard substantively and defeating its purpose. If this list was to be developed, they could be attached as guidelines aside of the standard. 7. The SAR DT states it will deal with "critical facilities" . The SRC suggest that the DT not use the word "critical" and adopt another term. There is a need to define in a single standard what the term "critical" means. Standards FAC-014 (R5.1.1); IRO-002-1 (R6) and others use the term "critical" as in: critical loads, critical infrastructure, critical assets. The Veg Management Team is asked to avoid making the current situation worse.

Response:

1. On the basis of the responses from stakeholders to Question #2 above, the SAR DT's assessment is that further specificity may be needed to aid in identifying which <200kV transmission lines should come under the purview of this standard. The SDT shall take under consideration other applicability parameter criteria, various stakeholder proposals including IROL violation potential.
2. The FERC Order includes the following language which indicates that FERC would support inclusion of any circuit below 200 kV that was subject to an IROL and the SAR has been written to allow this modification..
3. The SAR indicates that the Standard Drafting Team will review reporting criteria for Category 3 outages and will review the reporting requirement of Category 3 outages in R.3 and R.4.
4. The SDT shall consider producing a white paper to aid in clarifying the intent of the standard, however a field test is not contemplated at this time.
5. The SAR was revised to clarify that it is the ERO that will collect data and the Standard DT will receive the results of

Question #4			
Commenter	**Yes**	**No**	**Comment**
the ERO analysis and use it in developing the standard. 6. The standard DT will review the reporting exemptions to include all category outages under major disasters in Requirement R3.2. 7. The FERC Order includes the following language which indicates that FERC would support inclusion of any circuit below 200 kV that was subject to an IROL and the SAR has been written to allow this modification.			
ISO-NE	☑		1. The SAR indicates that a list of critical low voltage transmission lines will be provided to FERC. We do not interpret Order 693 to direct NERC to provide this list. Rather, we interpret that FERC asks for defining a criteria that would include low voltage transmission lines that have impact on Bulk Power System reliability. We do not think the list is required. 2. The SAR indicates: "The standard DT may consider other criteria in determining applicability of the standard to sub 200 kV lines…" Per Order 693, the criteria is quite clearly stated to be the transmission lines of less than 200 kV that could impact Bulk Power System reliability. We don't feel any other criteria would be necessary. Further, to identify the candidates that meet this criteria, we believe they should be determined by the Reliability Coordinator, similar to the PRC-023 standard, since the RC has the primary responsibility and knowledge of interconnection reliability impact. 3. We do not understand why the SDT considers removing Category 3 incidents. In our view, Category 3 outages are important information for assessing the effectiveness of a vegetation program. Since the industry started reporting vegetation-related outages about 3 years ago, data collected so far indicates that of a total of 98 reported vegetation outages, 67 of them were category 3 outages. With this high percentage, reporting of Category 3 events should be a must since the associated trends can provide valuable information to the TOs to aid its evaluation of the vegetation management program. 4. The white paper and field tests are a good idea and the SDT should be commended for these, especially the white paper. 5. Item 2 under the FERC Order 693 Items in the Detailed Description Section indicates the SDT will also collect outage data. While we understand that FERC has directed the ERO to collect outage data for transmission outages of lines that cross both federal and non-federal lands, we do not feel that it is the SDT's role to perform this task. We feel that this task should be performed by the ERO or a group separate from the SDT such

Question #4			
Commenter	**Yes**	**No**	**Comment**
			that the task does not add burden to the SDT which may slow down the standard development process or result in the standard development being driven by unanalyzed data and resulting in erroneous requirements. 6. With respect to reporting exemptions, our position during development of the previous version of this standard was to limit them. We commend the SDT's intention to clarify the outage exemptions under major disasters, but to consider including all category outage exemptions in the standard body is too prescriptive and will add to the already extended list. It can end up with a very long list of outage exemptions, thereby reducing the coverage of the standard substantively and defeating its purpose. If this list was to be developed, they could be attached as guidelines aside of the standard. 7. The SAR DT states it will deal with "critical facilities." The SRC suggest that the DT not use the word "critical" and adopt another term. There is a need to define in a single standard what the term critical means. Standards FAC-014 (R5.1.1); IRO-002-1 (R6) and others use the term "critical" as in: critical loads, critical infrastructure, critical assets. This Team is asked to avoid making the current situation worse.

Response:

1. On the basis of the responses from stakeholders to Question #2 above, the SAR DT's assessment is that further specificity may be needed to aid in identifying which <200kV transmission lines should come under the purview of this standard. The SDT shall take under consideration other applicability parameter criteria, various stakeholder proposals including IROL violation potential.
2. The FERC Order includes the following language which indicates that FERC would support inclusion of any circuit below 200 kV that was subject to an IROL and the SAR has been written to allow this modification..
3. The Standard Drafting Team intends to review reporting criteria for Category 3 outages in the proposed technical reference material and may review the reporting requirement of Category 3 outages in R.3 and R.4.
4. The SDT shall consider producing a white paper to aid in clarifying the intent of the standard, however a field test is not contemplated at this time.
5. The standard DT looks to receive the results of the ERO analysis and use it in developing the standard.
6. The standard DT will review the reporting exemptions to include all category outages under major disasters in Requirement R3.2.
7. The FERC Order includes the following language which indicates that FERC would support inclusion of any circuit below 200 kV that was subject to an IROL and the SAR has been written to allow this modification.

Question #4			
Commenter	**Yes**	**No**	**Comment**
MRO	☑		If the Regional Reliability Organization is removed as an applicable entity, what is the Regional Entity's responsible? How will a general consensus be formed? How do you get people to participate in this formation? For good planning and application of standards, methodologies need to be consistently applied through guidelines to the drafting teams. Specifically, this standard should provide consistent methodology that provides guidance to the transmission owner. In the next revision of the standard, the MRO requests that more authority be given to the applicable entities with respect to the latitude allowed them in removing trees to the legal limits of their agreement. The MRO commends FERC on empowering NERC and the SAR DT via their Order 693 to revisit the issue of clearances for lines on both Federal and non-Federal Lands. It has come to the attention of the MRO that Federal Forest Employees as well as BLM employees have begun the practice of chemically treating noxious weeds and invasive species on Federal Lands. he MRO would like to have FERC, NERC, and the Standard DT consider meeting with Federal Land Managers to discuss, on a National Level, the issue of herbicide application by utilities on Federal Lands. At the present time there are inconsistencies regionally on this issue that allow application in some regions but not in others.
Response: 1. The term RRO is no longer in use and RE (or regional entity) is now the preferred term for the former Regional Reliability Organizations. The term RE is defined in the delegation agreements between these organizations and the ERO. 2. Such a guideline exists and is available on the NERC website entitled "Standard Drafting Team Guidelines". 3. See answer #2 above. 4. The removal of trees within the limits stated in agreements is outside the scope of this standard. 5. The coordination of the use of herbicides is outside the scope of this standard.			
National Grid	☑		1) National Grid supports amending FAC-003-1 to bring the Standard into compliance with "latest version of the Reliability Standard Development Procedure and the ERO Sanctions Guidelines" as discussed in the SAR Background Information. 2) We do not support amendments to the Standard to address all of the issues raised by FERC Order 693. We believe most of the FERC's concerns can be addressed by

Question #4			
Commenter	**Yes**	**No**	**Comment**
			developing a "white paper" to better explain the Standard and guide its implementation. 3) National Grid does not support changing the basic approach to defining clearance from vegetation. The clearance 1 and clearance 2 concept adopts the two management approaches used by most TO's today and required in some state or ISO level standards. National Grid supports using the reference to IEEE 516 as the basis for clearance 2 for two reasons: 1 - there is no other definitive reference for flash over distances to vegetation and 2- decades of experience by TO's acrosss the North America suggest the IEEE 516 distances are more than adequate. The well known tree caused outages in 1996 and 2003 occurred as a result of hard contact with vegetation not flashover at distances close to those in IEEE 516. Furthermore, FERC accepted IEEE 516 as appropriate for use in vegetation management in the October 2006, NOPR. 4) National Grid supports amending the definition of a right-of-way though we are not clear on what is meant in the SAR language by "to encompass required clearing areas". National Grid is concerned with the interpretation of the present definition that the right-of-way includes uncleared fee owned or easement land reserved for future construction. In many jurisdictions the TO may not be allowed to remove trees from these areas. A "white paper" could better describe the definition and prevent future compliance issues stemming from an ambiguous definition.
Response: 1. The SAR DT thanks you for your comment. 2. The SAR indicates that the SDT will produce a technical white paper to clarify intent of the standard. 3. The SAR DT agrees with the commenter not to change the basic approach and recognizes that sections of IEEE 516 standard pertaining to minimum air insulation distances are applicable in determining minimum vegetation clearances to prevent flashovers. 4. The Standard DT will review the definition of ROW. See also answer #2 above.			
Northeast Utilities	☑		NU does not support the proposed revisions based on the issues raised by FERC Order 693. The Standard has not been in effect long enough to determine if there are any shortcomings with the current requirements. It is our position that the current clearance requirements are satisfactory in that a base minimum distance as provided under IEEE Section 516 is sufficient and there is the need for variations in the second level of clearances base on Regional needs and conditions. The revisions to the definition of "right-of-way" to encompass required clearance areas can e problematic as this could cause significant problems with current systems. There is no detailed description on what the new definition will include or what the actual impact will be to TO's. If the definition will include defined limits or widths of rights-of-

Question #4			
Commenter	**Yes**	**No**	**Comment**
			way this may affect current facilities that do not meet these distances. Second, there are areas where the company owns or possesses additional area beyond the current maintained right-of-way widths. Is it proposed that the new definition expand the limits of clearing or maintenance to include easemented or fee-owned areas beyond the current maintained limits? Until the new definition can be presented - it is difficult to support any changes at this time and we can only comment on the perceived negative impacts.
Response: The SDT will review the standard to address the Commission's determinations. The standard DT will review the definition of ROW. Note that the ERO is required to respond to the FERC directives.			
NYISO	☑		1. The SAR indicates that a list of critical low voltage transmission lines will be provided to FERC. We do not interpret Order 693 to direct NERC to provide this list. Rather, we interpret that FERC asks for defining a criteria that would include low voltage transmission lines that have impact on Bulk Power System reliability. We do not think the list is required. 2. The SAR indicates: "The standard DT may consider other criteria in determining applicability of the standard to sub 200kV lines…" Per Order 693, the criteria is quite clearly stated to be the transmission lines of less than 200 kV that could impact Bulk Power System reliability. We don't feel any other criteria would be necessary. Further, to identify the candidates that meet this criteria, we believe they should be determined by the Reliability Coordinator, similar to the PRC-023 standard, since the RC has the primary responsibility and knowledge of interconnection reliability impact. 3. We do not understand why the SDT considers removing Category 3 incidents? In our view, Category 3 outages are important information for assessing the effectiveness of vegetation program. Since the industry started reporting vegetation related outages about 3 years ago, data collected so far indicates that of a total of 98 reported vegetation outages, 67 of them were category 3 outages. With this high percentage, reporting of Category 3 events should be a must since the associated trends can provide valuable information to the TOs to aid its evaluation of the vegetation management program. 4. The white paper and field tests are a good idea and the SDT should be commended for these, especially the white paper. 5. Item 2 under the FERC Order 693 Items in the Detailed Description Section indicates

Question #4

Commenter	Yes	No	Comment
			the SDT will also collect outage data. While we understand that FERC has directed the ERO to collect outage data for transmission outages of lines that cross both federal and non-federal lands, we do not feel that it is the SDT's role to perform this task. We feel that this task should be performed by the ERO or a group separate from the SDT such that the task does not add burden to the SDT which may slow down the standard development process or result in the standard development being driven by unanalyzed data and resulting in erroneous requirements. 6. With respect to reporting exemptions, our position during development of the previous version of this standard was to limit them. We commend the SDT intention to clarify the outage exemptions under major disasters, but to consider including all category outage exemptions in the standard body is too prescriptive and will add to the already extended list. It can end up with a very long list of outage exemptions, thereby reducing the coverage of the standard substantively and defeating its purpose. If this list was to be developed, they could be attached as guidelines aside of the standard.

Response:

1. On the basis of the responses from stakeholders to Question #2 above, the SAR DT's assessment is that further specificity may be needed to aid in identifying which <200kV transmission lines should come under the purview of this standard. The SDT shall take under consideration other applicability parameter criteria, various stakeholder proposals including IROL violation potential..
2. The FERC Order includes the following language which indicates that FERC would support inclusion of any circuit below 200 kV that was subject to an IROL and the SAR has been written to allow this modification..
3. The Standard Drafting Team intends to review reporting criteria for Category 3 outages in the proposed technical reference material and may review the reporting requirement of Category 3 outages in R.3 and R.4.
4. The SAR indicates that the SDT will produce a white paper to aid in clarifying the intent of the standard, however a field test is not contemplated at this time.
5. The SDT looks to receive the results of the ERO analysis and use it in developing the standard.
6. The SDT will review the reporting exemptions to include all category outages under major disasters in Requirement R3.2.

Commenter	Yes	No	Comment
PGE	☑		1) Applicability 4.3 of the standard - PG&E believes the RE is in the best position to determine sub-200kV facilities are designated critical and covered under FAC-003-1. We suggest the ERO direct the RE to provide a list of sub-200kV lines designated critical along with methodology used to make that determination. 2) Clearances for lines on federal and non-federal lands - PG&E believes there should be no distinction between requirements on different lands. Vegetation encroachments have

Question #4			
Commenter	**Yes**	**No**	**Comment**
			the same impact regardless of land ownership. 3) Definition of right of way - agreed 4) Suitability of IEEE 516-2003 - PG&E believes the use of IEEE 516 as the standard for clearance requirements are adequate to ensure transmission system reliability provided the TO has an appropriate methodology for determining clearance at time of trim and an adequate cycle to prevent vegetation from encroaching within minimum distances. Use of ANSI Z133.3 or FedOSHA 1910, as suggested by FERC, is not appropriate as it is intended for worker safety and not system reliability. TO compliance with R1.2 of the standard should address concerns FERC has with maintaining minimum clearance. 5-7) Procedural items - No comment 8) Preparation of technical manual (white paper) - agreed 9) PG&E believes the current reporting requirements under R3 of the standard should be revised. Distinction is placed on fall-in's "in and out of the ROW" and may not be the best method for determining severity for reporting purposes. PG&E believes a better distinction is (a) green/healthy/no obvious decline and (b) dead or obvious signs of disease, decay or decline. A key component of any TMVP should be hazard tree mitigation regardless if in or out of the ROW. Suggested categories: Category 1 - Any grow-in (as currently stated). Category 2 - Any fall-in of a dead tree or one with obvious signs of disease, decay or decline in or out of the ROW. Category 3 - Either eliminate this category or specify healthy green tree or tree with no obvious signs of decline (if retained, be specific about this being for reporting purposes only) PG&E recognizes that tree failures, even if dead or diseased, are not necessarily an indicator of problematic VM program and the severity level should be reflected as such. Tree density along with other factors make 100% identification not possible. However, multiple occurrences could be an indicator of substandard performance and the current standard does remains silent in respect to hazard trees other than if in or out of the ROW.
Response:			

Question #4			
Commenter	**Yes**	**No**	**Comment**
1. On the basis of the responses from stakeholders to Question #2 above, the SAR DT's assessment is that further specificity may be needed to aid in identifying which <200kV transmission lines should come under the purview of this standard. The SDT shall take under consideration other applicability parameter criteria, various stakeholder proposals including IROL violation potential.. 2. The SAR DT concurs with the commenter with respect to applying this standard to Federal and non-Federal lands. The standard DT will evaluate the suitability of a case-by-case approach. 3. The standard DT will review the definition of ROW. 4. The SAR DT agrees with the commenter and recognizes that sections of IEEE 516 standard pertaining to minimum air insulation distances are applicable in determining minimum vegetation clearances to prevent flashovers. 5. n/a 6. n/a 7. n/a 8. The SAR indicates that the SDT will produce a technical white paper to clarify intent of the standard. 9. The SAR indicates that the SDT will review reporting criteria for Category 3 outages and will review the reporting requirement of Category 3 outages in R.3 and R.4. The SDT and Compliance Elements DT will review and assign Violation Severity Levels when modifying FAC-003-1.			
PGN	☑		Progress Energy Carolinas (PEC) and Progress Energy Florida (PEF) do not agree that each of 11 items listed in the SAR are necessary to improve reliability. The following comments are offered for each of the 11 items identified in the SAR detail description: 1. Standard Applicability: PEC and PEF believe that the current standard wording for determining facilities subject to this standard should not be revised. The standard as it is written provides for lines below 200kV, that are determined to impact the grid, to be subject to the standard. Extending the requirements to a bright line below 200kV, such as 100kV, will dilute the focus on those lines that impact grid reliability, lines >200kV, and shift attention to facilities, those <200kV, that do not necessarily impact grid reliability. Customer reliability is an issue that impacts customer satisfaction and is generally driven by state utility commissions. While some facilities above 200kV directly support customer load, transmission lines below 200kV primarily support customer load, and interruptions to those facilities generally reduce load on the grid. The majority of transmission facilities below 200 kV also have significantly different design/construction/operating characteristics and have not been cited as impacting bulk

Question #4			
Commenter	**Yes**	**No**	**Comment**
			power system reliability. For example, the Final Report on the August 14, 2003 Blackout in the United states and Canada: Causes and Recommendations April 2004 by the U.S.-Canada Power System Outage Task Force and all referenced major blackouts (pages 103-115) in that report, cited only outages which involved vegetation at line voltages above 200kV. Generally applying requirements that are appropriate for >200kV lines to lines less than 200kV will result in significant documentation and reporting of items such as restrictions, mitigation plans, off right-of-way vegetation-related outage investigation/ information and other issues, all of which dilutes the focus on lines that directly impact bulk power system reliability. Revising the standard to use general criteria or broad language for defining "Bulk Power System" transmission lines covered by the standard is a "one size fits all" approach. If that approach were taken, the standard would cover a significant number of transmission lines that have no direct impact on bulk power system reliability under standard planning/operating conditions, resulting in a significant cost burden for electric customers without improving "grid" reliability. PEC and PEF believe that the applicability provision of the standard should instead focus attention of the standard only on the transmission lines below 200kV that directly impact "Bulk Power System" reliability, as the current version requires. While PEC and PEF recognize some validity in the Commission's concern, PEC and PEF recommend that the applicability provision of this standard should be revised only if existing system design, planning or operating reliability criteria and parameters are considered as a basis for defining the applicability of the standard. To that end, PEC and PEF recommend each Regional Entity (RE) determine applicability of FAC-003 to those lines within the region that are between 100kV and 200KV, if, and only if, they are identified as operationally significant elements of Interconnection Reliability Operating Limits ("IROLs"). That is, any facility below 200kV that, by itself, would cause an Interconnected Reliability Limit Violation should the facility be outaged. 2. Issue of Clearances (Federal vs Non-Federal Lands): FAC-003-1 presently requires the transmission owner (TO) "identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on

Question #4			
Commenter	**Yes**	**No**	**Comment**
			conductor sway." The intent of this requirement is to ensure adequate clearances to prevent vegetation related outages. PEC and PEF believe that only the TO has the technical information required to determine the clearances that are necessary at the time of VM work and that any "federal lands exemption" to clearances will result in inadequate clearances for the existing conditions. Consistency in application of the TO's clearance requirements, not exceptions, is the only assurance in providing a uniform and reliable electrical system to meet the nation's current and future energy demands. Any exception for a case by case clearance approach to determine vegetation management activities/clearances on Federal lands will continue to drive inconsistency and/or delays associated with TO vegetation management decisions being driven by diverse vegetation management practices/beliefs and staff changes at the local level of Federal agencies. Vegetation-related outages have occurred on Federal lands as a result of this case by case approach, and if "Bulk Power Transmission System" lines continue to be addressed on a "case by case" basis on National Forest Service (or any other Federal lands), those lines will potentially be subject to a higher risk for vegetation-related outages, resulting in reduced reliability for the "Bulk Power System". PEC and PEF believe that reliability of the "Bulk Power System" should have the same focus on Federal and private lands and that the EEI MOU with federal agencies is an appropriate avenue for TO's to identify clearances on Federal lands, not an exemption in the language of a reliability standard. 3. Defining Right-of-Way: PEC and PEF agree that it is appropriate to further address the definition of "right-of-way". Corridor widths that exceed the design clearance requirements have been acquired for a variety of reasons in the past; future use, property line buffers, etc. Vegetation in those areas that would normally be outside of the corridor width necessary for reliable operation of the facility, but within an expanded easement area, should not be considered, or treated, different than vegetation that is outside of a defined easement/permit right-of-way corridor that was designed and acquired specifically for the reliable operation of a single line. 4. IEEE Standard for Minimum Clearances:

Question #4			
Commenter	**Yes**	**No**	**Comment**
			PEC and PEF believe that the IEEE 516-2003 tables are appropriate for defining the minimum acceptable clearances to prevent flashover between conductors and vegetation under all rated electrical operating conditions. Closer minimum clearances such as the minimum length of a support insulator could have been adopted as a "lowest common denominator" clearance. However the clearance in IEEE 516-2003 was adopted to ensure an additional margin of reliability. FERC staff has made references to the use of ANSI Z-133 which is a safety standard that addresses worker safety as well as the safety of the general public. The purpose of ANSI Z-133 is to address worker safety and is not focused on transmission line reliability, which is the purpose of FAC-003-1. OSHA, NESC and other related safety standards have clearances in excess of IEEE 516-2003. Those clearances are clearly focused on safety issues and will still apply to other aspects of design and operation of electric facilities (such as public and worker safety) but are not appropriate to be referenced in a vegetation management reliability standard as a flashover clearance. 5/6/7. Procedural Items: PEC and PEF agree that the procedural items related to formatting RRO references and revising the compliance elements to meet the new standard format should be addressed by the standard drafting team. 8. Technical Reference Materials: PEC and PEF agree that a "white paper" that defines the technical basis for the standard is appropriate. This type of document, if crafted by the drafting team, should help to avoid the potential for differences in interpretation of the standard's requirements by the various regions during the audit process. 9. Category 3 Outages: Since control off right-of-way vegetation is generally beyond control of the TO and since "fall-in" outages are random events that do not threaten grid reliability, PEC and PEF believe that the reporting of category 3 outages should be removed from the requirements. 10. Requirement R4:

<table>
<tr><th colspan="4">Question #4</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td>PEC and PEF believe that requirement R4 should be deleted from the standard, since the ERO formation provides for delegation of authority to the regional entities.

11. Reporting Exemptions:

PEC and PEF believe that the reporting requirement exemptions for natural disasters should include all categories of outages. For example, with outages caused by high winds, hurricanes, tornadoes, etc., it would be difficult (or practically impossible in some cases) to determine if the vegetation came from on, or off, the "right-of-way". In addition, the effort and time necessary to make that determination would result in delaying outage restoration efforts.</td></tr>
<tr><td colspan="4">Response:
1. On the basis of the responses from stakeholders to Question #2 above, the SAR DT's assessment is that further specificity may be needed to aid in identifying which <200kV transmission lines should come under the purview of this standard. The SDT shall take under consideration other applicability parameter criteria, various stakeholder proposals including IROL violation potential..
2. The SAR DT concurs with the commenter with respect to applying this standard to Federal and non-Federal lands. The standard DT will evaluate the suitability of a case-by-case approach.
3. The standard DT will review the definition of ROW.
4. The SAR DT agrees with the commenter and recognizes that sections of IEEE 516 standard pertaining to minimum air insulation distances are applicable in determining minimum vegetation clearances to prevent flashovers.
5. NERC standards must be updated to comply with new procedural requirements and must include compliance elements.
6. See #5
7. See #5
8. The SAR indicates that the SDT will produce a technical white paper to clarify intent of the standard.
9. The SAR indicates that the SDT will review reporting criteria for Category 3 outages and will review the reporting requirement of Category 3 outages in R.3 and R.4.
10. The standard DT will consider deletion of R.4.
11. The standard DT will review the reporting exemptions to include all category outages under major disasters in Requirement R3.2.</td></tr>
<tr><td>SERC VMS</td><td>☑</td><td></td><td>The SERC VMS does not agree that each of 11 items listed in the SAR are necessary to improve reliability. The following comments are offered for each of the 11 items identified in the SAR detail description:

1. Standard Applicability:</td></tr>
</table>

Question #4			
Commenter	**Yes**	**No**	**Comment**
			The SERC VMS disagrees with revising the 200 kV threshold for determining facilities subject to this standard. Extending the requirements to lines other than those >200kV will dilute the focus on those lines that impact grid reliability and shift attention to facilities, those <200kV. The reliability of lower voltage lines involves local customers' reliability and satisfaction hence that reliability should be addressed by local and state utility commissions. The majority of the >200kV lines are solely elements of the grid and and interruptions to those lines negatively impact grid reliability. The majority of the <200kV lines primarily support customer load, and interruptions to those facilities actually reduces load on the grid. The majority of transmission facilities below 200 kV also have significantly different design/construction/operating characteristics and have not been cited as impacting bulk power system reliability. For example, the Final Report on the August 14, 2003 Blackout in the United states and Canada: Causes and Recommendations April 2004 by the U.S.-Canada Power System Outage Task Force and all referenced major blackouts (pages 103-115) in that report, cited only outages which involved vegetation at line voltages above 200kV. Generally applying requirements that are appropriate for >200kV lines to lines less than 200kV will result in significant documentation and reporting of items such as restrictions, mitigation plans, off right-of-way vegetation-related outage investigation/ information and other issues, all of which dilutes the focus on lines that directly impact bulk power system reliability. Revising the standard to use general criteria or broad language for defining "Bulk Power System" transmission lines covered by the standard is a "one size fits all" approach. If that approach were taken, the standard would cover a significant number of transmission lines that have no direct impact on bulk power system reliability under standard planning/operating conditions, resulting in a significant cost burden for electric customers without improving "grid" reliability. The SERC VMS believes that the applicability provision of the standard should instead focus attention of the standard only on the transmission lines below 200kV that directly impact "Bulk Power System" reliability, as the current version requires. In sum, while the SERC VMS recognizes some validity in the Commission's concern, the SERC VMS recommends that the applicability provision of this standard should be revised only if existing system design, planning or operating reliability criteria and parameters

Question #4			
Commenter	**Yes**	**No**	**Comment**
			are considered as a basis for defining the applicability of the standard. To that end, the SERC VMS recommends each Regional Entity (RE) determine applicability of FAC-003 to those lines within the region that are between 100kV and 200KV, if, and only if, they are identified as operationally significant elements of Interconnection Reliability Operating Limits ("IROLs"). That is, any facility below 200kV that by itself would cause an Interconnected Reliability Limit Violation should the facility be outaged. 2. Issue of Clearances (Federal vs Non-Federal Lands): FAC-003-1 presently requires the transmission owner (TO) "identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway." The intent of this requirement is to ensure adequate clearances to prevent vegetation related outages. The SERC VMS believes that only the TO has the technical information required to determine the clearances that are necessary at the time of VM work and that any "federal lands exemption" to clearances will result in inadequate clearances for the existing conditions. Consistency in application of the TO's clearance requirements, not exceptions, is the only assurance in providing a uniform and reliable electrical system to meet the nation's current and future energy demands. Any exception for a case by case clearance approach to determine vegetation management activities/clearances on Federal lands will continue to drive inconsistency and/or delays associated with TO vegetation management decisions being driven by diverse vegetation management practices/beliefs and staff changes at the local level of Federal agencies. Vegetation-related outages have occurred on Federal lands as a result of this case by case approach, and if "Bulk Power Transmission System" lines continue to be addressed on a "case by case" basis on National Forest Service (or any other Federal lands), those lines will potentially be subject to a higher risk for vegetation-related outages, resulting in reduced reliability for the "Bulk Power System". The SERC VMS believes that reliability of the "Bulk Power System" should have the same focus on Federal and private lands and that the EEI MOU with federal agencies is the appropriate vehicle for TO's to identify clearance variances on Ferderal lands, not exemption language in the standard.

Question #4			
Commenter	**Yes**	**No**	**Comment**
			3. Defining Right-of-Way: The SERC VMS agrees that it is appropriate to further address the definition of "right-of-way". Corridor widths beyond design clearance requirements have been acquired for a variety of reasons in the past; future use, property line buffers, etc. Vegetation in those areas that would normally fall outside of the area necessary for operation of the facility should not be considered or treated different than vegetation that is outside of a defined easement/permit area that is designed for the reliable operation of an existing single line corridor. 4. IEEE Standard for Minimum Clearances: The SERC VMS disagrees with objections to the use of the IEEE 516-2003 clearance as the minimum acceptable distances for "Clearance 2". The IEEE 516-2003 tables are appropriate for defining the minimum acceptable clearances to prevent flashover between conductors and vegetation under all rated electrical operating conditions. Closer minimum clearances such as the minimum length of a support insulator could have been adopted as a "lowest common denominator" clearance. However the clearance in IEEE 516-2003 was adopted to ensure an additional margin of reliability. FERC staff references ANSI Z-133 which is a safety standard that addresses worker safety as well as the safety of the general public. As such, the purpose of ANSI Z-133 is to address worker safety and is not focused on transmission line reliability, which is the purpose of FAC-003-1. OSHA, NESC and other related safety standards have clearances in excess of IEEE 516-2003. Those clearances are clearly focused on safety issues and will still apply to other aspects of design and operation of electric facilities (such as public and worker safety) but are not appropriate to be referenced in a vegetation management reliability standard. 5/6/7. Procedural Items: The SERC VMS agrees that the procedural items related to formatting RRO references and additional compliance elements should be addressed by the standard drafting team. 8. Technical Reference Materials: The SERC VMS agrees that a "white paper" that defines the technical basis for the

Question #4			
Commenter	**Yes**	**No**	**Comment**
			standard is appropriate to avoid the potential for differences in interpretation of the standard's requirements during the various region's audit processes. 9. Category 3 Outages: Since the right to control off right-of-way vegetation is generally beyond control of the TO, the SERC VMS believes that the reporting of category 3 outages should be removed from the requirements. 10. Requirement R4: The SERC VMS believes that requirement R4 should be deleted from the standard, based on the ERO formation and the process for delegation of authority to the regional entities. 11. Reporting Exemptions: The SERC VMS believes that the reporting requirement exemptions for natural disasters should include all categories of outages. It would, for example, be difficult, without delaying restoration efforts, to determine if the vegetation from high winds, hurricanes, tornadoes, etc. is from on or off the "right-of-way".

Response:

1. On the basis of the responses from stakeholders to Question #2 above, the SAR DT's assessment is that further specificity may be needed to aid in identifying which <200kV transmission lines should come under the purview of this standard. The SDT shall take under consideration other applicability parameter criteria, various stakeholder proposals including IROL violation potential..
2. The SAR DT concurs with the commenter with respect to applying this standard to Federal and non-Federal lands. The standard DT will evaluate the suitability of a case-by-case approach.
3. The standard DT will review the definition of ROW.
4. The SAR DT agrees with the commenter and recognizes that sections of IEEE 516 standard pertaining to minimum air insulation distances are applicable in determining minimum vegetation clearances to prevent flashovers.
5. NERC standards must be updated to comply with new procedural requirements and must include compliance elements.
6. See #5
7. See #5
8. The SAR indicates that the SDT will produce a technical white paper to clarify intent of the standard.
9. The SAR indicates that the SDT will review reporting criteria for Category 3 outages and will review the reporting requirement of Category 3 outages in R.3 and R.4.

Question #4			
Commenter	**Yes**	**No**	**Comment**
10. The standard DT will consider deletion of R.4. 11. The standard DT will review the reporting exemptions to include all category outages under major disasters in Requirement R3.2.			
TVA	☑		We feel that the reporting of Category 3 outages should be eliminated. We agree with the need for a "white paper" to expand on definitions and intent. We feel that a defined maintainable width of right of way is more appropriate than the actual easement widths because easement widhts are not purchased or operated exclusively with or for vegetation manitenance activies. We will be pleased to share greater details on this concern if requested.
Response: The SAR DT thanks you for your comments.			
VELCO		☑	

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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on 1st Draft FAC-003-2 Vegetation Management SDT — Project 2007-07

The Vegetation Management Standard Drafting Team (VM SDT) thanks all commenters who submitted comments on the 1st draft of FAC-003-2 — Transmission Vegetation Management Program standard. This standard was posted for a 30-day public comment period from October 27, 2008 through November 25, 2008. Stakeholders were asked to provide feedback on the standard through a special Standard Comment Form. There were more than 60 sets of comments, including comments from more than 100 different people from over 60 companies representing each of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

Key differences between first posting and second posting of proposed FAC-003 -2 include:

- Replaced the CCZ concept found in R4 with a practical field measurement to address commenter's concerns.
- Eliminated the CCZ as the trigger of imminent threat in R2 to address commenter's concerns.
- Added a sub part to the TVMP (1.6) in order to address commenter's concerns regarding the elimination of Clearance 1. This change requires that the TO account for anticipated conductor movement.
- Developed VRF's and VSL's consistent with the NERC Drafting Team Guidelines.
- Created a second grow-in outage requirement to allow for different VRF levels based on the actual criticality of the line.

There were 3 strong minority views not resolved:

- Some commenters disagreed with the "zero tolerance" nature of the existing in-force standard.
- Some commenters disagreed with a minimum Vegetation Inspection frequency of one year.
- Some commenters want to retain Clearance 1 that is in the existing in-force standard.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — Transmission Owners, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	John Neagle	Associated Electric Cooperative Inc.	✓				✓	✓				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chris Bolick		SERC	1, 5, 6
2.	John Bussman		SERC	1, 5, 6
3.	Ralph Schulte		SERC	1, 5, 6
4.	Ted Hilmes		SERC	1, 5, 6
5.	John Settle		SERC	1, 5, 6
6.	Kevin White		SERC	1, 5, 6
7.	John Stickley		SERC	1, 5, 6
8.	Gary Highfill		SERC	1, 5, 6
9.	Jeff Neas		SERC	1, 5, 6
10.	Craig Thomas		SERC	1, 5, 6

Commenter		Organization	1	2	3	4	5	6	7	8	9	10
2.	Guy Zito	NPCC										✓

	Additional Member	Additional Organization	Region	Segment Selection

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10

1.	Ralph Rufrano	New York Powerm Authority	NPCC	5
2.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
3.	Rick White	Northeast Utilities	NPCC	1
4.	Greg Campoli	New York Independent System Operator	NPCC	2
5.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
6.	Chris De Graffenried	Consolidate Edison Co. of New York, Inc.	NPCC	1
7.	Don Nelson	Massachusetts Dept. of Public Utilities	NPCC	9
8.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
9.	Brian Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	Brian Evans-Mongeon	Utility Services, LLC	NPCC	6
13.	Mike Gildea	Constellation Energy	NPCC	6
14.	Lee Pedowicz	NPCC	NPCC	10

3.	Linda Perez	WECC Reliability Coordination										
4.	Jerry Paulson	Western Area Power Administration, Upper Great Plains Region										
5.	Jack Gardner (Chairman) Joe Spencer (SERC staff)	SERC Vegetation Management Subcommittee (VMS)										

	Additional Member	Additional Organization	Region	Segment Selection
1.	**Jack Gardner**	**Progress Energy Carolinas**	**SERC**	
2.	**Randy Gann**	**Alabama Power Co.**	**SERC**	
3.	**John Neagle**	**Associated Electric Cooperative, Inc.**	**SERC**	
4.	**Robby Trimble**	**E.ON U.S. Services Inc. for LG&E & KU Companies**	**SERC**	
5.	**Ralph Hale**	**Entergy**	**SERC**	
6.	**Marc Tunstall**	**Fayetteville Public Works Commission**	**SERC**	
7.	**Reggie Wallace**	**Fayetteville Public Works Commission**	**SERC**	

8.	Jerry Lindler	South Carolina Electric and Gas Company	SERC
9.	Richard Dearman	Tennessee Valley Authority	SERC
10.	Billy George	Duke Energy Carolinas	SERC

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	John Pinney	Progress Energy Florida	✓		✓		✓					

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Crews		FRCC	1, 3, 5

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Michael Gammon	Kansas City Power & Light	✓		✓		✓					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Todd Fridley		SPP	1, 3, 5
2.	Paul Beaulieu		SPP	1, 3, 5
3.	Duane Anstaett		SPP	1, 3, 5
4.	Gary O'Neil		SPP	1, 3, 5

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Ron Turley	Western Area Power Administration, Rocky Mountain Region	✓								✓	
9.	Jack Gardner	Progress Energy Carolinas	✓		✓		✓					
10.	Samuel Stonerock	Southern California Edison Company	✓		✓			✓				
11.	Jim Griffith	SERC OC Standards Review Group	✓		✓		✓					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Case	Entergy	SERC	1, 3, 5
2.	John Neagle	Assoc. Electric Coop., Inc.	SERC	1, 3, 5
3.	Greg Rowland	Duke Energy-Carolinas	SERC	1, 3, 5
4.	Bill Thompson	Dominion Virginia Power	SERC	1, 3, 5
5.	John Rembold	Southern Illinois Power Coop.	SERC	1, 3, 5
6.	Jason Marshall	Midwest ISO	SERC	2

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
7.	Randy Castello	Mississippi Power Co.	SERC	1, 3, 5
8.	Jimmy Etheridge	Georgia Transmission Corp.	SERC	1
9.	Danny Dees	Municipal electric Authority of Ga.	SERC	1, 3, 5
10.	Glenn Stephens	South Carolina Public Service Auth.	SERC	1, 3, 5
11.	Glen Thweatt	Big Rivers Electric Coop.	SERC	1, 3, 5
12.	Gerald Beckerle	Ameren	SERC	1, 3, 5
13.	Sam Holeman	Duke Energy - Carolinas	RFC	1, 3, 5
14.	Melinda Montgomery	Entergy	SERC	1, 3, 5
15.	Roman Carter	Southern Company	SERC	1, 3, 5

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Mike Neal	Western Utility Arborists	✓				✓				✓	
13.	John Tamsberg	Florida Power & Light	✓									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Eduardo Devarona	Florida Power & Light	FRCC	1
2.	Silvia Parada-Fortum	Florida Power & Light	FRCC	1
3.	Brian J. Murphy	Florida Power & Light	FRCC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Terry L. Blackwell	Santee Cooper	✓									

	Additional Member	Additional Organization	Region	Segment Selection
1.	S. T. Abrams	Santee Cooper	SERC	1
2.	Ben Fleming	Santee Cooper	SERC	1
3.	Kenny Sott	Santee Cooper	SERC	1
4.	Jim Peterson	Santee Cooper	SERC	1
5.	Glenn Stephens	Santee Cooper	SERC	1
6.	Kristi Boland	Santee Cooper	SERC	1
7.	Rene' Free	Santee Cooper	SERC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Roman Carter	Southern Company	✓		✓							

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Steve Burns	Gulf Power Co.	SERC	3
2.	Nancy Huddleston	Georgia Power Co.	SERC	3
3.	Ronald Reinike	Mississippi Power Co.	SERC	3
4.	Randall Gann	Alabama Power Co.	SERC	3
5.	Marc Butts	Southern Co. Transmission	SERC	1
6.	Raymond Vice	Southern Co. Transmission	SERC	1
7.	JT Wood	Southern Company Transmission	SERC	1
8.	Jim Busbin	Southern Co. Transmission	SERC	1
9.	Chris Wilson	Southern Co. Transmission	SERC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Charles Yeung	IRC Standards Review Committee		✓								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Patrick Brown	PJM	RFC	2
2.	Jim Castle	NYISO	NPCC	2
3.	Dan Rochester	IESO	NPCC	2
4.	Matt Goldberg	IEONE	NPCC	2
5.	Lourdes Estrada-Salinero	CAISO	WECC	2
6.	Anita Lee	AESO	WECC	2
7.	Steve Myers	ERCOT	ERCOT	2
8.	Bill Phillips	MISO	RFC	2

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Brent Ingebrigtson	E.ON U.S.	✓		✓		✓	✓				
18.	Denise Koehn	Bonneville Power Administration	✓		✓		✓	✓				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Jamrog	Vegetation/Access Road Mgmt	WECC	1
2.	Jerry Reding	Transmission Engineering	WECC	1
3.	Don Swanson	Transmission Line Maintenance Technical Svcs	WECC	1
4.	Michael Staats	Transmission Engineering	WECC	1

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
5.	Steven Bottemiller	Real Property Support Svcs	WECC	1
6.	Marian Wolcott	Real Property Svcs	WECC	1
7.	Jennifer Bailey	Transmission Line Maintenance Technical Svcs	WECC	1
8.	Stephen Larson	Legal	WECC	1
9.	Allen Chan	Legal	WECC	1
10	Robin Furrer	Transmission Field Services	WECC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19.	Jeffrey C. Mueller	Public Service Electric and Gas Company	✓		✓							
20.	Sam Ciccone	FirstEnergy	✓		✓	✓	✓	✓				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charles Olenik	FE	RFC	1
2.	Shawn Standish	FE	RFC	1
3.	Rebecca Spach	FE	RFC	1
4.	Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
21.	Joseph Knight	MRO NERC Standards Review Subcommittee	✓		✓		✓	✓				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Neal Balu	WPS	MRO	3, 4, 5, 6
2.	Terry Bilke	MISO	MRO	2
3.	Carol Gerou	MP	MRO	1, 3, 5, 6
4.	Jim Haigh	WAPA	MRO	1, 6
5.	Charles Lawrence	ATC	MRO	1
6.	Ken Goldsmith	ALTW	MRO	4
7.	Terry Harbour	MEC	MRO	1, 3, 5, 6
8.	Pam Sordet	XCEL	MRO	1, 3, 5, 6
9.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
10.	Eric Ruskamp	LES	MRO	1, 3, 5, 6

<table>
<tr><th colspan="2" rowspan="2">Commenter</th><th rowspan="2">Organization</th><th colspan="10">Industry Segment</th></tr>
<tr><th>1</th><th>2</th><th>3</th><th>4</th><th>5</th><th>6</th><th>7</th><th>8</th><th>9</th><th>10</th></tr>
<tr><td colspan="13">11. Joe DePoorter — MGE — MRO — 3, 4, 5, 6
12. Larry Brusseau — MRO — MRO — 10
13. Michael Brytowski — MRO — MRO — 10</td></tr>
<tr><td>22.</td><td>Jason L. Marshall</td><td>Midwest ISO Stakeholders Standards Collaborators</td><td></td><td>✓</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td colspan="13"><table><tr><th></th><th>Additional Member</th><th>Additional Organization</th><th>Region</th><th>Segment Selection</th></tr><tr><td>1.</td><td>Jim Cyrulewski</td><td>JDRJC Associates</td><td>RFC</td><td>8</td></tr><tr><td>2.</td><td>Greg Rowland</td><td>Duke Energy</td><td>SERC</td><td>1, 3, 5, 6</td></tr><tr><td>3.</td><td>Kirit Shah</td><td>Ameren</td><td>SERC</td><td>1</td></tr></table></td></tr>
<tr><td>23.</td><td>John Wolfmeyer</td><td>SERC Compliance Staff</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td>✓</td></tr>
<tr><td>24.</td><td>JAMES W. SMITH</td><td>ITC HOLDINGS</td><td>✓</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>25.</td><td>Richard Dearman</td><td>Tennessee Valley Authority</td><td>✓</td><td>✓</td><td>✓</td><td></td><td>✓</td><td></td><td></td><td></td><td>✓</td><td></td></tr>
<tr><td>26.</td><td>Chris Scanlon</td><td>Exelon</td><td>✓</td><td></td><td>✓</td><td></td><td>✓</td><td></td><td>✓</td><td></td><td></td><td></td></tr>
<tr><td>27.</td><td>Weston Davis</td><td>Central Maine Power Company</td><td>✓</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>28.</td><td>Thad Ness</td><td>American Electric Power (AEP)</td><td>✓</td><td></td><td>✓</td><td></td><td>✓</td><td>✓</td><td></td><td></td><td></td><td></td></tr>
<tr><td>29.</td><td>Deborah Schaneman</td><td>Platte River Power Authority</td><td>✓</td><td></td><td>✓</td><td></td><td>✓</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>30.</td><td>Alan Gale</td><td>City of Tallahassee</td><td>✓</td><td></td><td>✓</td><td></td><td>✓</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>31.</td><td>Fred Young</td><td>Northern California Power Agency (NCPA)</td><td></td><td></td><td></td><td>✓</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>32.</td><td>Jason Lietz</td><td>Northern Indiana Public Service Company</td><td>✓</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>33.</td><td>Chip Turner</td><td>Tampa Electric Company</td><td>✓</td><td></td><td>✓</td><td></td><td>✓</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>34.</td><td>Edward Bedder</td><td>Orange and Rockland Utilities Inc.</td><td>✓</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
</table>

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
35.	Jason Shaver	American Transmission Company	✓									
36.	Alice Druffel	Xcel Energy	✓		✓		✓	✓				
37.	Jeff Hackman	Ameren	✓		✓		✓	✓				
38.	John Humphrey	Nebraska Public Power District	✓									
39.	Jonathan Appelbaum	Long Island power Authority	✓									
40.	Robert (Bob) B. Suedkamp	USDA Forest Service, Southwestern Region, Regional Office for AZ and NM									✓	
41.	Kris Manchur	Manitoba Hydro	✓		✓		✓	✓				
42.	Jianmei Chai	Consumers Energy Company			✓	✓	✓					
43.	Dawn Travalini	National Grid	✓									
44.	Stephen Tankersley	Pacific Gas & Electric Co.	✓				✓					
45.	Rich Salgo	NV Energy (fka Sierra Pacific / Nevada Power Co.)	✓									
46.	Patricia vanMidde	San Diego Gas & Electric	✓		✓		✓					
47.	David Kiguel	Hydro One Networks Inc.	✓		✓							
48.	David Dworzak	Edison Electric Institute										
49.	George Czerniewski	Consolidated Edison Company of New York (CECONY)	✓									
50.	Tom Mathews and Steve Rueckert	WECC										✓

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
51.	Sreenath Thota	Arizona Public Service Company	✓	✓	✓	✓	✓	✓	✓	✓		
52.	Patrick Brown	PJM Interconnection		✓								
53.	William T. Rees	Baltimore Gas & Electric Company	✓									
54.	Greg Rowland	Duke Energy Corporation	✓		✓		✓	✓				
55.	Michael Pakeltis	CenterPoint Energy	✓									
56.	Ed Davis	Entergy Services	✓		✓		✓	✓				
57.	Anita Lee	Alberta Electric System Operator		✓								
58.	Richard Kafka	Pepco Holdings, Inc	✓		✓		✓	✓				
59.	Virginia Cook and Kim Wheeler	JEA	✓		✓		✓					
60.	Dan Rochester	Independent Electricity System Operator		✓								
61.	Karen Powell	Salt River Project	✓		✓		✓	✓				
62.	Rick White	Northeast Utilities	✓									
63.	Roger Champagne	Hydro-Québec TransEnergie (HQT)	✓									
64.	Kevin Koloini	Buckeye Power, Inc.			✓	✓	✓					
65.	Joe Knight	Great River Energy	✓		✓		✓	✓				

1. In the Purpose Statement the term "electric transmission systems" was changed to Bulk Electric System, and the Purpose statement was shortened by moving the various explanatory objectives to other locations in the revised Standard. Do you agree with the purpose statement? If not, please explain.

Summary Consideration: The SDT revised the purpose statement based on industry comments. The SDT returned to "electric transmission system" based on the comments that indicated confusion with the use of "BES". The SDT also inserted the word "those" in front of the phrase "vegetation-related outages" to clarify that not all vegetation-related outages lead to cascading. The revised purpose statement now reads:

Purpose: To improve the reliability of the electric transmission system by preventing those vegetation related outages that could lead to Cascading.

Organization	Agree?	Question 1 Comment
Associated Electric Cooperative Inc.	Disagree	The definition of Bulk Electric System includes most transmission lines operated at 100 kv and above. While Section A.4.2.1 limits the applicability of FAC-003-2 to 200 kv and higher transmission lines, the use of the term Bulk Electric System could cause unnecessary confusion. Associated Electric Cooperative Inc recommends the continued use of the term "electric transmission systems."
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
SERC Vegetation Management Subcommittee (VMS)	Disagree	The definition of the Bulk Electric System generally does not include radial transmission lines directly serving load and, in addition, includes all lines operated at 100 kV and above. Use of the term Bulk Electric System will cause unnecessary confusion to the industry concerning applicability of this standard. Therefore, we recommend the continued use of the undefined term "electric transmission systems."
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Progress Energy Florida	Disagree	The intent of the revision of the standard was to bring clarity to the standard. Referring to the BES in the purpose creates confusion as to the applicability of the standard. Therefore, Progress Energy recommends the continued use of the term "electric transmission systems."
Response: The SDT thanks you for your comment Based on the comments received, the SDT understands there may be confusion caused by "BES"		

Organization	Agree?	Question 1 Comment
and has revised the purpose statement to delete BES and return to electric transmission system.		
Kansas City Power & Light	Disagree	The definition of the bulk electric system does not match the scope of the systems covered by the vegetation management standard. If the term bulk electric system is used , it should exclude the areas not covered by the standard.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Western Area Power Administration, Rocky Mountain Region	Disagree	Use of the general term Bulk Electrical System creates unintentional confusion regarding the applicability of this standard to lines operated at 200 kV or higher and designated lines operated below 200 kV.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Progress Energy Carolinas	Disagree	The intent of the revision of the standard was to bring clarity to the standard. Referring to the BES in the purpose creates confusion as to the applicability of the standard. Therefore, Progress Energy recommends the continued use of the term "electric transmission systems."
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
SERC OC Standards Review Group	Disagree	The following comments are supplied by the SERC OC Standards Review Group (OCSRG): The definition of the Bulk Electric System generally does not include radial transmission lines directly serving load. The current standard covers all 200 kV and above transmission lines along with those lower voltage lines designated by the RRO while the BES includes all lines 100 kV and above. Use of the term Bulk Electric System will cause unnecessary confusion to the industry concerning applicability of this standard. Therefore, the SERC OCSRG recommends the continued use of the undefined term "electric transmission systems."
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Florida Power & Light	Disagree	The Purpose Statement of any regulation or standard should be completely consistent with the body of regulation or standard. Here the use of Bulk Electric System (which is defined as 100 kV and above) is inconsistent with the language of the Standard that states this Standard applies to 200 kV and above. One of the primary purposes of re-

Organization	Agree?	Question 1 Comment
		drafting a Reliability Standard is to clear up any previous confusion -- here the Purpose Statement instead of adding to clarity, adds an unnecessary element of confusion. Thus, the Purpose Statement should be re-written to state 200 Kv and above.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES". Rather than create a new class of BES (>200kv), the SDT revised the purpose statement to delete BES and return to electric transmission system.		
Southern Company	Disagree	The initial FAC-003-1 drafting team had a particular reason for not using Bulk Electric System for fear of it being widely recognized to characterize the entire networked transmission system. This reason was to limit possible confusion with the applicability of the Standard. The Bulk Electric System definition includes all lines of the grid operated at 100 kV and above. This term also does not necessarily include lines of any voltage class that are radial and directly serving load. Use of this term in lieu of "electric transmission systems" has the potential to cause additional confusion to the industry.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
E.ON U.S.	Disagree	The definition of the Bulk Electric System generally does not include radial transmission lines directly serving load and, in addition, includes all lines operated at 100 kV and above. Use of the term Bulk Electric System will cause unnecessary confusion to the industry concerning applicability of this standard. Therefore, we recommend the continued use of the undefined term "electric transmission systems."
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
MRO NERC Standards Review Subcommittee	Disagree	The standard specifically calls out that 200kV and higher are applicable to FAC-003. Changing to BES would imply all lines 100kV and above would be applicable.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Midwest ISO Stakeholders Standards Collaborators	Disagree	By definition Bulk Electric System includes most facilities 100 to 200 kV. The previous version of this standard appropriately restricted the applicability of the standard to these facilities by requiring the Regional Reliability Organization to identify only those facilities that are critical in this voltage class. This new version of the standards attempts to limit the 100-200 kV class applicability by having the RC identify the critical facilities. We believe to have one requirement of the standard say that it applies to all the BES and then another requirement to limit the

Organization	Agree?	Question 1 Comment
		application only confuses the applicability and recommend leaving the term "electric transmission systems" in the definition.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
SERC Compliance Staff	Disagree	The definition of the Bulk Electric System generally includes all lines operated at 100 kV and above and may exclude radial lines to load only. The standard is applicable to lines operated at greater than 200 kV regardless of their function. SERC staff does not believe that it is the intent of the standard to address lines operated at less than 200 kV unless they are deemed to be critical to the operation of the BES nor do we believe it is the intent to exclude radials to load only from the applicability. Use of the term Bulk Electric System will cause unnecessary confusion to the industry concerning applicability of this standard. Therefore, we recommend the continued use of the undefined term "electric transmission systems."
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
ITC HOLDINGS	Disagree	ITC does not agree with the new purpose statement. The NERC Glossary of terms states that the BES ?.generally operated at voltages of 100kV or higher and the Applicability in Section 4 clearly states the standard is intended to apply to all line voltages of 200kV and above and those lines designated by the Reliability Coordinator (4.2.1) as being subjected to this standard. Using the term Bulk Electric System (BES) clearly sends a confusing message and should be eliminated. Thus the term of "electric transmission system" is appropriate for the standard
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Tennessee Valley Authority	Disagree	TVA feels the use of the term Bulk Electric System will cause unnecessary confusion to the industry concerning applicability of this standard. TVA recommends the continued use of the undefined term "electric transmission systems. TVA recommends changing the phrase "by preventing vegetation-related outages that could lead to Cascading" to "by preventing those vegetation-related outages that could lead to Cascading", this removes the improper inference that each vegetation-related outage leads to Cascading
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system. Additionally, at your suggestion and that of others, the SDT has added the qualifying word "those" to define that the standard should address interconnection reliability and security.		

Organization	Agree?	Question 1 Comment
Central Maine Power Company	Disagree	Central Maine Power suggests that a definition be provided for Bulk Power.
Response: The SDT is uncertain of the need to define Bulk Power.		
American Electric Power (AEP)	Disagree	American Electric Power ("AEP") does not agree with this purpose statement. First, it is clear from the Applicability (in Section 4) that the standard applies only to certain lines, not to the entire Bulk Electric System (BES). Reference to the BES in the Purpose statement tends to muddy the water, potentially leading to an assumption that the Standard indeed applies to the entire BES. AEP suggests that the term BES used herein be replaced with "electric transmission system" or "transmission grid". Second, the phrase "by preventing vegetation-related outages that could lead to Cascading" should be changed to "by preventing those vegetation-related outages that could lead to Cascading", to remove any suggestion that all vegetation-related outages could lead to Cascading.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by “BES” and has revised the purpose statement to delete BES and return to electric transmission system. Additionally, at your suggestion and that of others, the SDT has added the qualifying word “those” to define that the standard should address interconnection reliability and security.		
Tampa Electric Company	Disagree	NERC glossary of terms defines the Bulk Electric System as "the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher." This, at a minimum, could lead to confusion over what impacts the reliability of the Grid by potentially including facilities less than 200 kV.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by “BES” and has revised the purpose statement to delete BES and return to electric transmission system.		
Orange and Rockland Utilities Inc.	Disagree	The use of the term "Bulk Electric System" (BES) could lead to confusion. In most regions BES includes lines with operating voltages equal to or greater than 100kV. The Standard is intended to apply to all lines with operating voltages equal to or greater than 200kV, and only those sub-200kV lines which are designated by the Reliability Coordinator (paragraph 4.2.1). Use of the words "electric transmission systems" rather than BES would eliminate this potential source of confusion.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by “BES” and has revised the purpose statement to delete BES and return to electric transmission system.		
American Transmission	Disagree	ATC disagrees with changing the term "electric transmission systems" to "Bulk Electric System". This standard applies to 200 kV and higher transmission lines not all BES facilities. Suggested Purpose statement: To maintain

Organization	Agree?	Question 1 Comment
Company		the reliability of the electric transmission system by requiring entities to have and implement a transmission vegetation management plan.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system. We also appreciate your suggested purpose statement but based on others' comments to be more specific about the reliability need for this standard we modified the purpose statement as seen in the Summary Consideration above.		
Ameren	Disagree	By definition, the capitalized term, Bulk Electric System, is defined to include most facilities 100 kV and above. The previous version of this standard appropriately restricted the applicability of the standard to those facilities operating above 200kV and any additional facilities identified by the Regional Reliability Organization as critical. This new version of the standards attempts to limit the 100-200 kV class applicability by having the RC identify the critical facilities. We believe the change creates unnecessary and undesirable confusion in that one requirement of the standard says that it applies to all the BES and then another requirement limits the application. Leaving the term "electric transmission systems" in the definition is preferable to that proposed.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Nebraska Public Power District	Disagree	NPPD disagrees with the change to bulk electric system, because it creates confusion on the applicability. This standard only applies to certain lines and not the entire (bulk) system.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Manitoba Hydro	Disagree	Manitoba Hydro disagrees with changing "electric transmission systems" to "Bulk Electric System" because BES applies to facilities 100kV and above which may not have an impact on system reliability.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Consumers Energy Company	Disagree	Consumers Energy disagrees with changing the current "electric transmission systems" to "bulk electric system". This change will create confusion and can lead to a discrepancy concerning lines operating below 200kV that may be included in the "bulk electric system" but are otherwise excluded from this standard.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES"		

Organization	Agree?	Question 1 Comment
and has revised the purpose statement to delete BES and return to electric transmission system.		
National Grid	Disagree	Use of the term Bulk Electric System will cause unnecessary confusion to the industry concerning applicability of this Standard.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Edison Electric Institute	Disagree	The purpose of the standard should be revised to state 'To maintain minimum clearances sufficient to avoid any vegetation-related Sustained Outages for all applicable conditions.' This is the identical wording taken from Order No. 693, Paragraph 731.
Response: The SDT appreciates your comments to use the exact wording in the FERC Order for the purpose statement. However, the SDT believes strongly that the interconnected system reliability which FERC should be protecting is better defined by the second posting statement. For instance, there are 200 kV circuits which serve only local load. Outages to these circuits from vegetation are no different than from other causes. The issue for this standard should be the prevention of vegetation outages that will threaten the interconnection.		
Consolidated Edison Company of New York (CECONY)	Disagree	The phrase "Bulk Electric System" (BES) is somewhat misleading. BES includes transmission voltages greater than 100kV but this Standard addresses transmission lines with operating voltages at or above 200kV and only those lines below 200kV designated by the Reliability Coordinator. Use of the phrase "electric transmission circuits" or something similar rather than BES would reduce confusion.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Arizona Public Service Company	Disagree	APS suggest the following change; To improve the reliability of the Bulk Electric System by preventing vegetation related outages. This is a reliability standard APS would suggest removing "that could lead to widespread cascading failures" from the purpose statement.
Response: The SDT thanks you for your comment. However, the SDT believes strongly that the interconnected system reliability which FERC should be protecting is better defined by the second posting statement. For instance, there are 200 kV circuits which serve only local load. Outages to these circuits from vegetation are no different than from other causes. The issue for this standard should be the prevention of vegetation outages that will threaten the interconnection.		
Duke Energy Corporation	Disagree	Duke disagrees with changing "electric transmission systems" to "Bulk Electric System" because this creates the potential for confusion or indiscriminate expansion of the scope of applicability to 100kV facilities which may not

Organization	Agree?	Question 1 Comment
		have an impact on network system reliability. Using "Bulk Electric System" confuses the applicability of the standard. Duke believes that Section 4.2 has the specificity to clearly designate any applicable lines. Thus, the term "electric transmission systems" is appropriate.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Entergy Services	Disagree	Entergy disagrees with changing "electric transmission systems" to "Bulk Electric System." Historically, the definition of the Bulk Electric System has included all lines operated at voltages 100 kV and greater. The above change in terminology will add ambiguity to which lines this standard is applicable. Entergy is concerned about the potential for this ambiguity leading to the expansion of the applicability of the standard to include lines below 200kv.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
JEA	Disagree	We disagree with this change as it may cause confusion on the applicability of the standard as the BES is generally 100kV and above, but this standard generally applies to 200kV and above.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Great River Energy	Disagree	The standard specifically calls out that 200kV and higher are applicable to FAC-003. Changing to BES would imply all lines 100kV and above would be applicable
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Western Area Power Administration, Upper Great Plains Region	Agree	Western (UGPR) agrees with the objective of using the FERC/NERC defined term "Bulk Electric System", but believe that the FERC/NERC definition includes lines above 100 kV. It needs to be clearly understood that use of the generic term in the Purpose section does not supersede the specific definitions (greater than 200 kV, etc.) contained in the Facilities section.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system based on a overwhelming industry preference for the latter.		

Organization	Agree?	Question 1 Comment
Platte River Power Authority	Agree	The use of the approved terminology, Bulk Electric System, from the NERC Glossary of Terms is better than the undefined term electric transmission systems.
Response The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system based on a overwhelming industry preference for the latter.		
Northeast Utilities	Agree	Agree with the term "bulk electric system. "Disagree with the wording of the Purpose Statement; The Purpose statement reads "To improve the reliability of the bulk electric system by preventing vegetation related outages that could lead to Cascading." One vegetation-caused outage does not in and of itself cause Cascading. Cascading will only result due to a combination of events - either multiple vegetation outages during the same time or an outage coupled with equipment malfunction or operational errors. The document seems to be internally inconsistent in this regard. The Technical Reference for FAC-003-2 notes that outages due to trees falling from outside the right-of-way or other outage causes on a critical facility would not constitute a possible cascading effect. If one occurrence of these types of outages would not constitute a cascading potential then one must wonder why an outage from a tree contact within the right-of-way is considered a possible cascading event? Suggest rewording the statement to exclude the comment about Cascading and use "by preventing vegetation related outages on critical transmission facilities."
Response: The SDT thanks you for your comment. The SDT acknowledges that a single vegetation-related outage will not, in the absence of other contributing factors cause a cascading collapse of the electric grid. The intent of the standard is to prevent those vegetation-related outages that could contribute to a cascading event. Therefore based on your comment, and others', the SDT added "those" to further refine the intent.		
Southern California Edison Company	Agree	Q1: SCE agrees in part with the proposed revisions to the purpose statement. However, we believe the phrase "vegetation related outages" is unnecessarily vague. Based on the content of certain requirements in Version 2, the intent of this standard is and should be to prevent sustained outages due to vegetation-to-line contacts. SCE respectfully suggests the purpose statement (A3) be revised to read: "To improve the reliability of the Bulk Electric System by preventing vegetation-to-line contacts that could lead to Cascading?
Response: The SDT thanks you for your comment. The SDT focuses this standard on preventing vegetation-related Sustained Outages rather than vegetation to line contacts as you recommend because not all contacts result in Sustained Outages.		
BCTC	Agree	Yes, we agree.
Western Utility Arborists	Agree	Yes, we agree.

Organization	Agree?	Question 1 Comment
Bonneville Power Administration	Agree	
FirstEnergy	Agree	
Santee Cooper	Agree	
Exelon	Agree	
City of Tallahassee	Agree	
Northern California Power Agency (NCPA)	Agree	
Northern Indiana Public Service Company	Agree	
Xcel Energy	Agree	
Long Island power Authority	Agree	
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	
Pacific Gas & Electric Co.	Agree	
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	
San Diego Gas & Electric	Agree	
Hydro One Networks Inc.	Agree	

Organization	Agree?	Question 1 Comment
NPCC	Agree	
WECC Reliability Coordination	Agree	
WECC	Agree	
Baltimore Gas & Electric Company	Agree	
CenterPoint Energy	Agree	
Pepco Holdings, Inc	Agree	
Independent Electricity System Operator	Agree	
Salt River Project	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
Buckeye Power, Inc.	Agree	
Response: The SDT thank you for your participation. The SDT made revisions to the purpose statement in response to industry comment. In order to avoid confusion the SDT replace “BES” with “electric transmission system” and inserted the word “those” in front of the phrase “vegetation-related outages”.		

2. The Reliability Coordinator was chosen as the proper entity to identify sub-200kV transmission lines to be subject to this standard (see applicability, R9, and R10). Do you agree with this choice? If not, please explain.

Summary Consideration: A majority of the commenters agreed with the selection of Reliability Coordinator to designate sub-200 kV transmission lines to which this standard applies. However several dissenters recommended the Planning Coordinator (PC) as a more appropriate choice. The stakeholders' main reason for preferring the PC is the longer time horizon that the PC normally considers in the performance of its function. Typically an RC considers the real time to months ahead operating time horizons. A PC typically takes into account a planning horizon extending out several years. An example cited by some stakeholders is the assignment to the PC for identifying applicable lines in NERC Standard PRC-023 R3 – Transmission Relay Loadability.

Upon consideration of the sound rationale for replacement of RC with PC, the SDT changed Requirement R10 and R11 as well as the applicability section 4.2 to reflect this.

Some commenters suggested that facilities critical to the derivation of an IROL should be the only criterion for selection of lines subject to this standard. The Independent System Operator - Regional Transmission Owner Council (ISO/RTO Council) and individual ISOs offered that all transmission lines of the BES are applicable under this standard regardless of voltage class or impact on the BES. However the ISO/RTO Council believes that there are other standards that determine critical facilities. The SDT agreed that including facilities critical to the derivation of an IROL would be a technically acceptable threshold to determine applicability of sub-200 kV lines, but concluded that there are other thresholds that define circuits important to the reliability of the Bulk Electric System (e.g., the WECC region's Major Transfer Paths). The SDT wishes to allow the application of other criteria in addition to IROL to support to the greatest extent possible the reliability of the BES.

Several commenters recommended the inclusion of a dispute resolution process and coordination between Transmission Owner/RC in this standard to ensure agreement and consistency across regions. The SDT believes that the language in Requirement R10 which specifies "consultation" **OR CONSENSUS** between the Planning Coordinator and its member Transmission Owners, would minimize the need for a dispute resolution process. Additionally, other Standards in which the PC determines important circuits to the reliability of the BES include no such mechanism.

Requirements R9 and R10 (now R10 and R11) were changed as follows:

R9. Each Planning Coordinator shall prepare and review annually, a list lines that are operated below 200kV, if any, which are subject to this standard. . Each Planning Coordinator shall consult with its Transmission Owner(s) and neighboring Planning Coordinators to obtain input to develop the list.

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R10. Each Planning Coordinator shall develop and document its method for assessing the reliability significance of sub-200kV lines whose loss would place the grid at an unacceptable risk of instability, separation, or cascading failures.

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R10.1 Transmission lines whose loss would result in the exceedance of an Interconnection Reliability Operating Limit (IROL)¶
R10.2 Transmission lines

Organization	Agree?	Question 2 Comment
SERC Vegetation Management Subcommittee (VMS)		The SERC Vegetation Management Subcommittee (VMS) abstains on this question. However, we believe that this comment form should provide an option to abstain in addition to the options to agree/disagree.
Response: Thank you for your comment. The SDT does not believe this issue can be addressed by this team. However it is appropriate to raise this limitation with the NERC staff.		
American Transmission Company	Disagree	Requirements 9 and 10 should be deleted and replaced with the following language. Proposed Language The Transmission Owner shall include those transmission lines below 200 kV that that are associated with an established IROL. (This language could either be uses as a requirement or inserted into the Applicability section.) Our statement provides a clear decision on which lower voltage lines have to be included in an entities transmission vegetation management program.
Response: Thank you for your comments. The SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11)as well as the applicability section 4.2. The SDT believes that further guidance is needed to ensure all regions have evaluated and developed a list of sub 200kV lines that are subject to this standard. The FERC indicated that not all regions produced such lists and directed the ERO, using this stakeholder process, to develop a mechanism to provide the list. The proposed R10 continues to require consultation between the PC and Transmission Owner as well as neighboring PCs. In R10, the SDT believes that the PC has the requisite expertise and planning horizon perspective to designate sub 200kV lines to comply with this standard. Limiting the choice of lines to solely IROL lines may not achieve the purpose of this standard. The SDT intends in R10 that the PC employ a technically sound criterion when designating transmission lines to be subject to this standard which includes IROL calculations.		
Associated Electric Cooperative Inc.	Disagree	Associated Electric Cooperative Inc does not believe the Reliability Coordinator (RC) is the appropriate entity to determine whether or not selected sub-200 kv transmission lines should be subject to this standard. The planning horizon for the RC is typically much shorter than the time needed to incorporate a sub-200 kv transmission line into a vegetation management program. Associated recommends Planning Coordinator be designated as the applicable functional entity and be substituted wherever Reliability Coordinator appears in the Standard.
Response: Thank you for your comment. The SDT agrees and has replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2.		
Santee Cooper	Disagree	The RC should not define applicable lines that are operated below 200 kV. PRC023 requires the Planning Coordinator to define transmission lines operated at 100 kV to 200 kV that are considered critical to the reliability of

Organization	Agree?	Question 2 Comment
		the Bulk Electric System. Multiple lists will lead to confusion among electric utilities.
Response: Thank you for your comments. Several commenters offered sound rationale for replacement of RC with PC including a reference to NERC Standard PRC-023 Relay Loadability. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this.		
Southern Company	Disagree	The use of the Reliability Coordinator as the entity for identifying sub-200 kV lines is inconsistent with the approach used in other NERC standards, such as PRC-023. Other NERC standards utilize the Planning Coordinator or the RRO as the entity. We feel the Planning Coordinator would be the appropriate entity for identifying sub-200 kV lines covered by FAC-003-2.
Response: Thank you for your comments. Several commenters offered sound rationale for replacement of RC with PC including a reference to NERC Standard PRC-023 Relay Loadability. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this.		
SERC OC Standards Review Group	Disagree	The SERC OCSRG does not believe that the RC is the appropriate entity to identify sub-200 kV transmissions to be subject to this standard. Vegetation Management programs are longer than the normal operating horizons of RCs. We believe that the proper function to identify sub-200 kV transmission lines subject to this standard is the Planning Coordinator. This must be consistent with PRC-023, Requirement 3. We also recommend that a process be established for dispute resolution. NERC should develop a comprehensive approach to the determination of "critical" facilities rather than pushing a piecemeal approach as evidenced by this standard and PRC-023, among others.
Response: Thank you for your comments. Several commenters offered sound rationale for replacement of RC with PC including a reference to NERC Standard PRC-023 Relay Loadability. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this. In regard to dispute resolution process, the SDT believes that the requirement for consultation implies cooperation and collaboration between entities and a dispute resolution process is not currently needed. **In regard to a comprehensive approach to identify/determine “critical” facilities, the SDT agrees in concept but has some reservations. The reservations are based upon doubt that “one size can fit all” for every context of every standard. A critical facility for one situation may not be a critical facility for another. For example, the PRC standard seeks to identify facilities that may need to carry very heavy contingent flows to stop a cascade. This FAC-003 standard seeks to identify facilities for which their OUTAGE (due to vegetation) would create reliability concerns for the BES.**		
IRC Standards Review Committee	Disagree	We do not see the role of an RC or PC in a vegetation management standard. All Transmission Owners need to ensure they have a vegetation program to avoid unnecessary tripping of transmission lines, at any voltage levels and regardless of their impacts on the BES. Identification of critical facilities is not a part of this standard; it belongs to other standards that deal with SOL/IROL calculations, SPS, protection and critical infrastructure protection. R10 and

Organization	Agree?	Question 2 Comment
		R11 should be removed from the standard.
Response: Thank you for your comments. The SDT does not agree with removal of R10 and R11. The SDT does not believe the burden of compliance for low voltage circuits with little or no impact on the BES is reasonable for electricity consumers to bear. FERC has acknowledged the same and given guidance for this standard's applicability which provides that a distinction exists in sub-200 kV facilities. The SDT sought to develop a reasonable mechanism that balances these concerns when we drafted R9 and R10 (now R10 and R11). The SDT agrees with respect to use of the label "critical". This standard does not intend to classify facilities as critical, that is left to CIP-002.		
Independent Electricity System Operator	Disagree	The IESO does not see a role for an RC or PC in a vegetation management standard. All Transmission Owners need to ensure they have a vegetation program to avoid unnecessary tripping of transmission lines, particularly those that impact the BES. We are of the view that identification of critical facilities is not a part of this standard; it belongs to other standards that deal with SOL/IROL calculations, SPS, protection and critical infrastructure protection. R10 and R11 should therefore be removed from the standard.
Response: Thank you for your comments. The SDT does not agree with removal of R10 and R11. The SDT does not believe the burden of compliance for low voltage circuits with little or no impact on the BES is reasonable for electricity consumers to bear. FERC has acknowledged the same and given guidance for this standards' applicability which provides that a distinction exists in sub-200 kV facilities. The SDT sought to develop a reasonable mechanism that balances these concerns when we drafted R9 and R10 (now R10 and R11). The SDT agrees with respect to use of the label "critical". This standard does not intend to classify facilities as critical, that is left to CIP-002.		
Hydro-Quebec Transenergie (HQT)	Disagree	HQT believe that the Planning Coordinator (PC) should be the entity responsible to determine the elements part of the BPS submitted to this Standard, and in fact for all other Standards. Those elements should be determined by an impact based methodology, as used in NPCC, with no voltage limitation and no fixed voltage threshold level as imposed in Applicability 4.2.
Response: Thank you for your comments. Several commenters offered sound rationale for replacement of RC with PC. The SDT agreed with the rationale and changed Requirement R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this. The SDT believes each PC can determine the appropriate threshold to assure the reliability of the BES and does not believe it necessary to instruct PCs in this regard in this Standard.		
MRO NERC Standards Review Subcommittee	Disagree	The MRO disagrees that the RC is appropriately positioned to identify and designate any sub-200kV lines that should be subject to this standard. The MRO believes that the lines below 200kV should include only those that are currently classified as Interconnection Reliability Operating Limit (IROL) lines which are already defined and listed for registered entities. As such R10 and R11 should be eliminated from these standards along with the RC in the applicability section.
Response: Thank you for your comments. The SDT agrees that the RC is not appropriately positioned and replaced the RC with the PC. The SDT believes		

Organization	Agree?	Question 2 Comment
that further guidance is needed to ensure all regions have evaluated and developed a list of sub 200kV lines that are subject to this standard. FERC indicated that not all regions produced such lists and directed the ERO, using this stakeholder process, to develop a mechanism to provide the list. The proposed R10 continues to require consultation between the PC and Transmission Owner as well as neighboring PCs. In R10, the SDT believes that the PC has the requisite expertise and planning horizon perspective to designate sub 200kV lines to comply with this standard. Limiting the choice of lines to solely those included in the derivation of an IROL may not achieve the purpose of this standard. The SDT intends in R10 that the PC employ a technically sound criterion when designating transmission lines to be subject to this standard, which could include those included in the derivation of IROL calculations.		
Midwest ISO Stakeholders Standards Collaborators	Disagree	We do not believe that the RC is the appropriate entity to identify those facilities sub-200 kV facilities that this standard should apply to. Vegetation management is not performed in the operating horizon. Rather it is performed in the planning and operations planning horizons. The RC should not be distracted from focusing on the operating horizon by this task. We believe what the standard is essentially requiring is identifying critical facilities. There are other similar requirements such as PRC-023-1 R3 that appear to require the determination of critical facilities even though the term critical facilities is not defined. We believe this represents broader issue that requires NERC to define critical facilities. Failure to do so could result in the inefficient identification of multiple lists of critical facilities for specific requirements that may ultimately be challenged in due process.
Response: Thank you for your comments. Several commenters offered sound rationale for replacement of RC with PC including a reference to NERC Standard PRC-023 Relay Loadability. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this. Your comment on time horizon further supports this change. **In regard to a comprehensive approach to identify/determine circuits, the SDT agrees in concept but has some reservations. The reservations are based upon doubt that “one size can fit all” for every context of every standard. A critical facility for one situation may not be a critical facility for another. For example, the PRC standard seeks to identify facilities that may need to carry very heavy contingent flows to stop a cascade. This FAC-003 standard seeks to identify facilities for which their OUTAGE (due to vegetation) would create reliability concerns for the BES.**		
Ameren	Disagree	While the RC would seemingly have the wide area view to make the assignment appropriate, the standard is really trying to determine the entity who can assess the risk to the BES of a vegetation-related outage. The management of that risk is in the venue of the Transmission Planner who, in the long term, designs the system and, in the Operating Horizon, establishes the parameters of operation that will lead to reliability. Certainly, the RC is preferable to the RE (RRO). However, the TP is preferable to the RC.
Response: Thank you for your comments. Several commenters offered sound rationale for replacement of RC with PC including a reference to NERC Standard PRC-023 Relay Loadability. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this. The PC performs its function over a similarly long term time horizon as the Transmission Planner but would be better positioned as a result of the PC’s wider area view.		

Organization	Agree?	Question 2 Comment
Manitoba Hydro	Disagree	Manitoba Hydro disagrees that the RC is appropriately positioned to identify and designate any sub-200kV lines that should be subject to this standard. Lines below 200kV should include only those that are currently classified as Interconnection Reliability Operating Limit (IROL) lines which are already defined and listed for registered entities. As such R10 and R11 should be eliminated from this standards along with the RC in the applicability section.
Response: Thank you for your comments. The SDT agrees that the RC is not appropriately positioned and replaced the RC with the PC in the revised draft proposed Standard. **The SDT agrees that lines included in the derivation of an IROL should be included in the PC's list; there are other lines that have importance to the reliability of the BES, e.g. the WECC Major Transfer Paths. The PC is well qualified for this differentiation task and may choose to develop thresholds which match the needs of its region. Therefore, the SDT respectfully disagrees that the only sub-200 kV circuits for which this standard should apply are those stated by MH.**		
WECC	Disagree	WECC believes the Regional Entity should remain the proper entity to identify sub-200kV transmission lines subject to this standard. The Regional Entity is in the best position to work with Transmission Owners (Transmission Owners) and Reliability Coordinators across the interconnection to determine critical sub-200kV transmission lines.
Response: Thank you for your comments. Several commenters offered sound rationale for replacement of RC with PC. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this.		
PJM Interconnection	Disagree	The RC or PC should not play a role in the vegetation management standard. All Transmission Owners need to ensure they have a vegetation program to avoid unnecessary tripping of transmission lines, at any voltage levels and regardless of their impacts on the BES. Identification of critical facilities is not a part of this standard; it belongs to other standards that deal with SOL/IROL calculations, SPS, protection and critical infrastructure protection. R10 and R11 should be removed from the standard.
Response: Thank you for your comments. The SDT does not agree with removal of R10 and R11. The SDT does not believe the burden of compliance for low voltage circuits with little or no impact on the BES is reasonable for electricity consumers to bear. FERC has acknowledged the same and given guidance for this standards' applicability which provides that a distinction exists in sub-200 kV facilities. The SDT sought to develop a reasonable mechanism that balances these concerns when we drafted R10 and R11. The SDT agrees with respect to use of the label "critical". This standard does not intend to classify facilities as critical, that is left to CIP-002		
National Grid	Disagree	No opinion.
Response: Thank you for your participation.		

Organization	Agree?	Question 2 Comment
Duke Energy Corporation	Disagree	Duke believes that the Planning Coordinator is the appropriate entity to identify any sub-200 kV facilities that this standard should apply to. Of note is the time frame once a sub-200kV line is designated, then the Transmission Owner has 12 months before the line is subject to the standard. This coincides with the longer term view of the Planning Coordinator.
Response: Thank you for your comment. Several commenters offered sound rationale for replacement of RC with PC. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this.		
Great River Energy	Disagree	GRE disagrees that the RC is appropriately positioned to identify and designate any sub-200kV lines that should be subject to this standard. GRE believes that the lines below 200kV should include only those that are currently classified as Interconnection Reliability Operating Limit (IROL) lines which are already defined and listed for registered entities. As such R10 and R11 should be eliminated from this standards along with the RC in the applicability section.
Response: Thank you for your comments. The SDT agrees that the RC is not appropriately positioned and replaced the RC with the PC in the draft proposed Standard. **The SDT agrees that lines included in the derivation of an IROL should be included in the PC's list, there are other lines that have importance to the reliability of the BES, e.g. the WECC Major Transfer Paths. The PC is well qualified for this differentiation task and may choose to develop thresholds which match the needs of its region. Therefore, the SDT respectfully disagrees that the only sub-200 kV circuits for which this standard should apply are those stated by GRE.**		
WECC Reliability Coordination	Agree	This would be a new function in WECC RC; we are not currently staffed to perform this function.
Response: Thank you for your comment. The SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2.		
Western Area Power Administration, Upper Great Plains Region	Agree	Western's (UGPR) agreement is contingent upon maintaining the requirements for consulting with Transmission Owners and neighboring Reliability Coordinator(s) and documenting the method for assessing the reliability significance of each included line as contained in R10 and R11.
Response: Thank you for your comment. The SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2. The proposed R10 continues to require consultation between the PC and Transmission Owner as well as neighboring PCs.		
Progress Energy Florida	Agree	While Progress Energy agrees that the RC is the appropriate entity, the drafting team should consider including a dispute resolution requirement for those instances when the Transmission Owner and the Reliability Coordinator disagree as to which lines below 200 kV should be included.

Organization	Agree?	Question 2 Comment
Response: Thank you for your comment. Several commenters offered sound rationale for replacement of RC with PC. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this. In regard to dispute resolution process, the SDT believes that the requirement for consultation implies cooperation and collaboration between entities and a dispute resolution process is not currently needed.		
Kansas City Power & Light	Agree	I agree with the qualification that the Reliability Coordinator identify sub-200kv facilities in consultation with its Transmission Owner(s) and neighboring Reliability Coordinator(s).
Response: Thank you for your comment. The SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2. The proposed R10 continues to require consultation between the PC and Transmission Owner as well as neighboring PCs.		
Progress Energy Carolinas	Agree	While Progress Energy agrees that the RC is the appropriate entity, the drafting team should consider including a dispute resolution requirement for those instances when the Transmission Owner and the Reliability Coordinator disagree as to which lines below 200 kV should be included.
Response: Thank you for your comment. Several commenters offered sound rationale for replacement of RC with PC. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this. In regard to dispute resolution process, the SDT believes that the requirement for consultation implies cooperation and collaboration between entities and a dispute resolution process is not currently needed.		
Southern California Edison Company	Agree	Q2: No comments.
Response: Thank you for your participation.		
Western Utility Arborists	Agree	Yes, we agree.
Response: Thank you for your comment. Please see the summary consideration – based on stakeholder comments, the SDT changed the applicability in Requirements R9 and R10 (now R10 and R11) from the Reliability Coordinator to the Planning Coordinator.		
ITC HOLDINGS	Agree	ITC agrees that the Reliability Coordinator is the appropriate entity to identify and designate any sub - 200kV lines deemed applicable to the standard with the concurrence of the Transmission Owner.
Response: Thank you for your comment. Based on other stakeholder comments, the SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2. The proposed R10 continues to require consultation between the PC and Transmission Owner as well as		

Organization	Agree?	Question 2 Comment
neighboring PCs.		
Tennessee Valley Authority	Agree	TVA agrees with Comment question 2
Response: Thank you for your comment. Based on other stakeholder comments, the SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2. The proposed R10 continues to require consultation between the PC and Transmission Owner as well as neighboring PCs.		
American Electric Power (AEP)	Agree	AEP concurs with the drafting team that the Reliability Coordinator is the appropriate entity for identifying sub-200kV lines (if any) that would be subject to the Standard.
Response: Thank you for your comment. Based on other stakeholder comments, the SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2.		
Platte River Power Authority	Agree	The Reliability Coordinator is better able to identify lines under 200 kv that would exceed an Interconnection Reliability Operating Limit (IROL), cause instability, uncontrolled separation, or cascading outages resulting from a vegetation related outage than the Regional Entity.
Response: Thank you for your comment. Based on other stakeholder comments, the SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2.		
Nebraska Public Power District	Agree	NPPD agrees that the Reliability Coordinator is the correct body for identification of any sub 200kV lines that would be subject to this standard.
Response: Thank you for your comment. Based on other stakeholder comments, the SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2.		
Consolidated Edison Company of New York (CECONY)	Agree	CECONY agrees provided that R10 remains the same as is currently written. This states that the Reliability Coordinator, in consultation with the Transmission Owner, shall jointly prepare and keep current, a list of designated applicable lines.
Response: Thank you for your comment. Based on other stakeholder comments, the SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2. The proposed R10 continues to require consultation between the PC and Transmission Owner as well as neighboring PCs.		

Organization	Agree?	Question 2 Comment
Northeast Utilities	Agree	One question: Will the Reliability Coordinators use consistent criteria for listing sub 200-kV facilities to be included under FAC-003-2? The purpose of FAC-003 is to ensure inter-regional reliability and to focus on the reliable operation of these lines. By leaving the decision up to the individual Reliability Coordinators - there is the potential for local differences in determining which sub-200-kV facilities may be critical. This could result in some transmission owners having to include certain facilities under the requirements of FAC-003-2 where in other regions of the country - similar facilities may not be included by the Reliability Coordinator. Although there have been criteria established to guide the Reliability Coordinators in the determination of sub-200-KV facilities for inclusion under FAC-003-2 - is this sufficient to ensure uniformity throughout the US? Perhaps some involvement at the Regional Entity level at least, is warranted.
Response: Thank you for your comments. The SDT agrees with the points you raise regarding inter-regional reliability. This is addressed in part by the requirement R10 where consultation with neighboring entities is specified. We feel that the requirement R10 ensures that inter-regional coordination is addressed. **In addition several commenters offered sound rationale for replacement of RC with PC. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this.**		
Baltimore Gas & Electric Company	Agree	The documented method to assess the reliability significance of sub-200 kV lines referenced in R10 should be put out for comment by the Reliability Coordinator to the regulated entities and FERC/NERC before it is finalized.
Response: Thank you for your comment. Several commenters offered sound rationale for replacement of RC with PC. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this.		
Entergy Services	Agree	The applicability of this standard should state that it is not applicable to insulated transmission lines, such as underground lines.
Response: Thank you for your comment. The SDT believes that the general term "transmission line" along with the associated tables and terminology sufficiently eliminates any misconception or misdirected thought that this standard applies to underground conductors or other conductors that are insulated in a manner that would prevent their flashover to trees.		
Pepco Holdings, Inc	Agree	FERC Order 693 essentially has the RC replacing the RRO.
Response: Thank you for your comment. Several commenters offered sound rationale for replacement of RC with PC. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this.		
BCTC	Agree	Yes, we agree.

Organization	Agree?	Question 2 Comment
Response: Thank you for your participation.		
Buckeye Power, Inc.	Agree	Agreed on this question.
Response: Thank you for your participation.		
Western Area Power Administration, Rocky Mountain Region	Agree	
Florida Power & Light	Agree	
Bonneville Power Administration	Agree	
FirstEnergy	Agree	
SERC Compliance Staff	Agree	
Exelon	Agree	
Central Maine Power Company	Agree	
City of Tallahassee	Agree	
Northern California Power Agency (NCPA)	Agree	
Northern Indiana Public Service Company	Agree	
Tampa Electric Company	Agree	
Orange and Rockland Utilities	Agree	

Organization	Agree?	Question 2 Comment
Inc.		
Long Island power Authority	Agree	
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	
Consumers Energy Company	Agree	
Pacific Gas & Electric Co.	Agree	
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	
San Diego Gas & Electric	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
Arizona Public Service Co.	Agree	
JEA	Agree	
CenterPoint Energy	Agree	
Salt River Project	Agree	

3. In R1 the proposed standard replaces "prepare, and keep current" with "have", replaces the list of terms, "objectives, practices, approved procedures, and work specifications," with "designed to control vegetation", defines the "active transmission line ROW", and specifies that the transmission vegetation management program applies to that area. Do you agree with R1? If not, please explain.

Summary Consideration:

Regarding the use of "have", some commenters requested that the original wording should remain. However, the SDT and some other commenters note that proving whether something is "current" is an opportunity for compliance ambiguity and unintended discrimination. Therefore, the SDT continues to use "have" in the second draft.

A few commenters raised the issue concerning Critical Clearance Zone in this question and that has been addressed with the substantive changes which have been made to the second draft standard.

While some commenters prefer the list of terms, the SDT chose the term "methods" as a more global, all encompassing term that allows transmission owners flexibility in developing their Transmission Vegetation Management Program. The SDT agrees the list of terms is helpful. However, when listed in a Requirement there is an expectation that all such terms must be included and evidence produced to show compliance. The list of terms can be included in the technical reference to assist Transmission Owners.

Finally, many commenters wanted more specificity in the reference material to describe the "Active Transmission Line Right-of-Way". The SDT has provided additional clarification in the technical reference document.

The revised R1 is shown below:

R1. Each Transmission Owner shall have a documented transmission vegetation management program that describes how it conducts work on its Active Transmission Line Rights of Way to prevent Sustained Outages due to vegetation, considering all possible locations the conductor may occupy under the effects of sag and sway throughout its operating range under rated conditions. The transmission vegetation management program shall:

1.1. Specify the methods that the Transmission Owner may use to control vegetation.

1.2. Specify a Vegetation Inspection frequency of at least once per calendar year that takes into account local[3] and environmental factors.

1.3. Require an annual plan. An annual work plan shall:

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1.3.1 Identify the applicable lines to be maintained

1.3.2 Identify the work to be performed

1.3.3 Be flexible to adjust to changing conditions and to findings from Vegetation Inspections. Adjustments to the plan within the year are permissible.

1.3.4 Take into consideration permitting and scheduling requirements from landowners or regulatory authorities.

1.4. Require a process or procedure for response to an imminent threat of a vegetation related Sustained Outage. The process or procedure shall specify actions which shall include immediate communication of the threat to the responsible control center.

1.5. Specify an interim corrective action process for use when the Transmission Owner is constrained from performing vegetation maintenance as planned.

1.6 Specify the maintenance strategies used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that Table 1 clearances in Attachment 1 are never violated. The maintenance strategies shall consider the sag and sway of the conductor throughout its operating range under rated conditions.

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Organization	Agree?	Question 3 Comment
Bonneville Power Administration	Disagree	R1: BPA understands that version 2 clearly states that the Critical Clearance Zone does not extend beyond the Active Transmission Right of Way. The Technical reference provides examples of active and inactive portions o corridors. BPA feels this list of examples is not exhaustive and therefore the technical reference language shou be changed to read, "Examples of active and inactive portions of corridors include, BUT MAY NOT BE LIMITED Transmission Owner:" Also, since it is clearly stated on page 2 of the Standard, that the Critical Clearance Zone shall not extend beyond the limits of the Active Transmission Line Right of Way, and that these limits are not specifically defined because they may vary by circumstance, the definition of Active Transmission Line Right of Way on Page 2 of the Standard should include a statement that the actual physical limits of each Active Right of Way will be determined by the Transmission Owner. R1.1: BPA recommends retaining the version 1 language of "objectives, practices, approved procedures, and work specifications" as it is more instructive in what is expected of a TMVP then the version 2 replacement language of "methodologies."

Response: Thank you for your comment. The issues concerning Critical Clearance Zone have been addressed by changes which have been made to

Organization	Agree?	Question 3 Comment
the draft standard. The definition and use of the term "Critical Clearance Zone" have both been removed from the revised standard. **The SDT chose, for the revised standard, the term "methods" as a more global, all encompassing term that allows transmission owners flexibility in developing their Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1.**		
Associated Electric Cooperative Inc.	Disagree	Associated Electric Cooperative Inc agrees with the changes described in Question 3 except for the definition of Active Transmission Line Right of Way. Associated suggests the term be revised to "Active Right-of-Way" for consistency with the present Glossary term "Right-of-Way" and that the definition of Active Right-of-Way be revised to explicitly permit the Transmission Owner to solely determine the appropriate width. A suggested definition is "Active Right-of-Way: The portion of Right-of-Way utilized for active transmission facilities. The width of the Active Right-of-Way, as determined by the Transmission Owner, shall be consistent with the Transmission Owner's normal standards and practices and shall be consistent with good utility practice for other transmission lines of similar voltage and configuration. Inactive or unused portions of the Right-of-Way, intended for future transmission lines or other facilities, may be excluded from the Active Right-of-Way."
Response: Thank you for your comment. While there is logic in your proposal to simply modify Rights-of-Way with "Active", previous commenters wanted to include "Transmission" to clearly eliminate the case of rights-of-way that include lower voltage facilities.		
NPCC	Disagree	While we agree with the suggested changes, we believe that the Transmission Vegetation Management Program should be focused on removal of incompatible vegetation from the Active Right of Way. We recommend using the following phrase in R1: "designed to remove incompatible vegetation on its Active Transmission Lines' Rights 0f Way" instead of "designed to control vegetation on its Active Transmission Lines' Rights of Way ". Incompatible vegetation should be defined as any vegetation which has the potential to grow tall enough to jeopardize the integrity of an applicable transmission line by growing into the Critical Clearance Zone or falling into the Critical Clearance Zone. This would provide clear guidance to all stakeholders, support long term vegetation management philosophies, and complement methods such as IVM where incompatible vegetation is completely removed, and compatible vegetation is encouraged to proliferate, thereby helping to control incompatible vegetation in an environmentally positive manner. Removal of incompatible vegetation is superior to pruning, topping, and trimming in terms of short and long term reliability of the Bulk Electric System. This language would also serve to align NERC and FERC with Transmission Owners who attempt achieve the highest degree of reliability by exercising their full easement rights in cases where strong opposition from landowners and public officials is encountered. If such language is adopted it should apply to R1 and the Transmission Vegetation Management Program. It should be made clear in the technical reference document that removal, rather than pruning of incompatible vegetation is the philosophy that must be incorporated into the Transmission Vegetation Management Program. It

Organization	Agree?	Question 3 Comment
		must be clearly explained that Transmission Owners have the flexibility to perform removals gradually over several treatment cycles in sensitive areas as long as pruning is performed as an interim measure to ensure that Critical Clearance Zone encroachments and on-Right of Way fall overs do not occur. It must also be made clear that the presence of incompatible vegetation on the Right of Way will always occur and does not in itself constitute a violation of the Standard.
Response: Thank you for your comment. The SDT has addressed removal of incompatible vegetation as a best management practice by referencing ANSI A300 as a footnote to Requirement R1. It is noted that A300 is not a requirement of the standard, only a best management practice. We will address your other comments in the technical reference paper for industry guidance.		
Baltimore Gas & Electric Company	Disagree	I agree with the simplification of the language, but I am uncomfortable with the definition of Active Right-of-Way (R/W). The definition in FAC-003-2 and the examples used in the white paper continue to leave room for interpretation, particularly with respect to the example where only one circuit is installed on a double circuit tower. Moreover, there may be circumstances where the Active R/W is relatively narrow and the utility has an Inactive R/W or otherwise owns land adjacent to the Active R/W that can be maintained to protect the facilities from grow-ins. Consequently, consideration should be given to require utilities to protect lines from grow-ins into the Critical Clearance Zone regardless of whether or not the R/W is Active or Inactive as long as the utility has the legal ability to do the necessary work.
Response: Thank you for your comment. The Standard clearly addresses that all grow-ins are considered to be within the active right-of-way, regardless of whether or not the tree is rooted within the active right-of-way. The Standard requires that such vegetation be managed as described in the Transmission Owner's Transmission Vegetation Management Program. Additionally, the SDT has revised the drawings and guidance in the technical reference paper to eliminate the confusion you and others detected.		
Northern Indiana Public Service Company	Disagree	Use of the term "have" is a notable and unnecessary weakening versus the terms "prepare and keep current". One of the key lessons learned from past vegetation related outages and subsequent investigations and reports is that successful UVM programs must continually adapt to changing circumstances which means practices and procedures must be kept current. Why weaken this expectation in the standard? Also, I disagree with the elimination from the revised standard the present requirement R1 that all Transmission Vegetation Management Programs include certain essential components (objectives, practices, approved procedures & work specifications). Why make changes that imply Transmission Vegetation Management Program's without these key components are acceptable?
Response: Thank you for your comment. The SDT believes that the term "have" is appropriate. While sympathetic to your perception about the terms, in order to "have" a Transmission Vegetation Management Program it had to have been prepared. Latency of the plan, like all plans required by NERC standards, can easily be addressed in compliance without creating the task of proving "current" if it is included in the Requirement. The SDT chose, for the revised standard, the term "methods" as a more global, all encompassing term that allows transmission owners flexibility in developing their		

Organization	Agree?	Question 3 Comment
Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1.		
Xcel Energy	Disagree	We propose adding the following language to the end of the definition for "Active Transmission Line Right of Way": OR OTHER PURPOSES, REGARDLESS OF THE PREMISES DIMENSIONS IN ANY EASEMENT, LICENSE AGREEMENT OR OTHER LAND RIGHT DOCUMENT.
Response: Thank you for your comment. The SDT believes that the definition of "active transmission line right-of-way" is appropriate for meeting the objectives of the Standard. This topic will be covered in the technical reference document which will be issued with the next draft of the Standard.		
Hydro One Networks Inc.	Disagree	We agree in changing the text as proposed only if R1 is expanded as suggested below. The standard as written is primarily, if not exclusively focused on outage prevention through one means, to keep vegetation out of the Critical Clearance Zone. The burden to accomplish this is placed on the Transmission Owner/Operator as it should be. The first section highlights that a program is required, but does not provide a requirement above this simplistic view, and from our perspective the Measures do not introduce any further rigour. This simplistic approach, in our opinion, does not adequately address the reliability risks associated with the various methodologies of managing vegetation. The White Paper notes removal is superior to pruning in ensuring tree conflicts do not occur. The White Paper includes elements of vegetation management risks, but the revised standard for the most part excludes this issue. One could argue that the audits and fines will manage reliability risks, but we are not convinced that this will do so in a consistent and adequate manner. There are numerous clearance risk factors associated with managing vegetation on rights of way. Some of these are: accurate measurement of conductor sag, accurate measurement of vegetation, vegetation growth rate, conductor sway, tree movement. If one looks at Table 1, the Clearance Distances are to the nearest cm or 1/100 of a foot. This makes one wonder, how realistic are the expectations laid out in the standard? To manage the risks around the Critical Clearance Zone the Standard requires each Transmission Owner to work with these precise numbers and build in a margin of safety to manage the situation. Will each Transmission Owner use identical criteria to trigger work? This doubtful, so this leads one to believe that the standard has not been designed to produce consistent results, which in our opinion is the case. So one has varied field conditions that are difficult to nail down, precise clearance requirements to the nearest 1/100? and the likelihood of inconsistent margins of safety. We realize that the audit process will help to assess these situations, but it may not be enough to achieve a somewhat uniform risk profile across the transmission systems. Other standards that we are familiar with include a margin of safety such as added clearance above the absolute minimum recognizing that it may not be practical to work to such precise measures. Examples of standards that use this approach to ensure consistent and reliable results include OHSA and the Canadian Standards Association. We are not advocating that this standard follows an identical approach, but do want to highlight that the standard may fall short in the area of managing vegetation management risks which in turn have a direct impact on reliability. Considering the above, it is suggested that the aspect of managing vegetation reliability risks be added to the White Paper to allow Transmission Owners to develop somewhat consistent criteria. Further on the topic of managing risk. We believe that reliability risks are

Organization	Agree?	Question 3 Comment
		directly related to the amount of incompatible vegetation on a right of way that is approaching the Critical Clearance Zone. Incompatible vegetation would be vegetation that has the potential to grow into the Critical Clearance Zone at full growth. We suggest that risks could be reduced significantly by including direction in the standard concerning the management of incompatible vegetation. This would drive a greater degree of consistency among Transmission Owners and would reduce the amount of vegetation on rights of way that have the potential to cause flashover. In addition, this would reinforce the reliability risks associated with vegetation, not just from a clearance perspective but also from a volume perspective, and would provide a more comprehensive view for the public and interest groups. In order to respond to what we consider a shortcoming of the proposed standard, our suggestion would be to expand R1.1 similar to the following: Specify the methodologies that the Transmission Owner uses to control vegetation and demonstrate that the removal of non-compatible vegetation is a focus within the plan. It is recognized that reliability risks increase appreciably with an increase in incompatible vegetation on an active right of way, and the Transmission Owner is required to remove incompatible vegetation at a point no later in time when it poses a threat to the reliability of the transmission line. Exceptions include vegetation used for designated visual screens, trees of a historic significance, vegetation to control erosion, agreements made at the time of environmental approval for construction,???etc.
Response: Thank you for your comments. The SDT revised the standard so that it no longer references the "Critical Clearance Zone." The SDT chose, in the revised standard, to use the term "methods" as a more global, all encompassing term that allows transmission owners flexibility in developing their Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1. Moreover, we believe the Standard as subsequently revised provides flexibility for Transmission Owners to develop their own vegetation management programs. But we are sensitive to the issues you raised and have tried to define through the subsections in R1 that specific elements are necessary.		
CenterPoint Energy	Disagree	The term "Active Transmission Line Right-of-way" is not defined in sufficient detail in the Definition of Terms Used in the Standard section to know how to apply the Requirements. The term causes a circular reference problem with the term "Critical Clearance Zone" that refers to the "limits of the Active Transmission Line Right-of-way" which has no specific definition as to its limits within the proposed revised Standard. There is an attempt to differentiate between the "Total R.O.W." and the "Active R.O.W." portion by using the phrase "occupied by active transmission facilities", but no specific limits of such occupation are included within the definition. Are "active transmission facilities" only the physical energized conductors as-is, where-is? Does "occupied" include the conductor vertical and horizontal movement envelope and any horizontal and vertical electrical clearance as well? Does the term "Active Transmission Line Right-of-way" refer to the legal limits of the right-of-way? The new R9 includes the phrase "within the extent of its easement and/or legal rights" which seems to support that definition. The phrase "a strip of land" seems to refer to a metes and bounds description, but how is that relevant when no specific land space is defined, such as with a railroad occupation or Corp of Engineer's permit? On page 16 of the Technical Reference, there is a reference to the Bramble and Byrnes wire-border zone technique. The wire zone

Organization	Agree?	Question 3 Comment
		is defined in the Technical Reference as "the section of a utility transmission right-of-way directly under the wires and extending outward about 10 feet on each side". Are the limits of the "Active Transmission Line Right-of-way" intended to be equivalent to the Bramble and Byrnes wire zone, or is the Transmission Owner to use its discretion to define the limits? The examples in the Technical Reference document do not define the limits of the "active transmission facilities" either. The "Active R.O.W." limit in Figure 1 and Figure 3 is arbitrary. Figure 2 is supposed to display an edge zone for vegetation to exist, which implies an "Inactive R.O.W" portion, but no such zone is defined. Figure 1 also has trees shown inside the "Total R.O.W." and within the "Inactive R.O.W." that are tall enough and close enough to be within falling distance of the active transmission line which seems averse to R7 for vegetation falling into a conductor when the Transmission Owner likely has legal rights to remove them if they are within the "Total R.O.W." and are within falling distance. The interpretation of M7 will be difficult in this case without a specific method to define the "Active R.O.W." portion of the Total R.O.W. We recommend deleting the confusing terms "Active Transmission Line Right-of-way and "Critical Clearance Zone" and returning to the prior Clearance 2 Requirement with the newly specified minimum clearances from Table I of Attachment 1 as an alternative approach should the definition of minimum vegetation clearance distances remain integral to the Standard.
Response: Thank you for your comments. The Critical Clearance Zone concept has been removed from the latest draft of the Standard. While the SDT believes that the definition of "active transmission line right-of-way" in the Standard is appropriate, this concept will be further reviewed by the SDT in the context of the technical reference and your comments. And we agree that a further explanation is required to eliminate questions like the ones you raised. The new examples in the technical reference should eliminate that ambiguity.		
JEA	Disagree	The standard should EITHER require an entity to have and follow a program OR hold an entity to performance standards, but not both. Requiring a procedure in conjunction with performance requirements incents the entity to write procedures that meet only the minimum requirements of the standard, as they will be audited and held accountable for what is documented and performance against that. If performance requirements are in place without the concurrent requirement for a procedure, then the entity is incented to develop procedures that meet best practices in order to assure that they will meet or beat the performance standards, because in this scenario, such procedures do not expose the entity to additional compliance risk while enhancing reliability.
Response: Thank you for your comment. The Standard provides the framework for Transmission Owners to develop and implement an effective transmission vegetation management program in support of the main reliability objective: preventing sustained outages of transmission lines that could lead to cascading. During the drafting process, many members of the drafting team asserted that several of the requirements are merely facilitative in nature and would be unnecessary if sustained outages are successfully prevented. Because this standard is relatively new compared to standards that were developed from operating policies that had been followed for decades, there is a sense that the benefits of "defense in depth" (keeping the facilitating requirements) may be warranted until entities have more experience with mandatory vegetation management.		

Organization	Agree?	Question 3 Comment
Salt River Project	Disagree	R1.1 states "Specify the methodologies that the Transmission Owner uses to control vegetation". The word "methodologies" does not adequately replace "objectives, practices, approved procedures, and work specifications". Recommend to keep the original wording.
Response: Thank you for your comments. The SDT chose "methods" in R1 part 1.1 to provide flexibility for Transmission Owners to develop their own vegetation management programs. ANSI A300 has been referenced as a best management practice in a footnote to 1.1. The Technical Reference Document provides examples of the variations in methods that are necessary due to the wide diversity of vegetation across North America.		
Hydro-Quebec Transenergie (HQT)	Disagree	While we agree with the suggested changes for the terms proposed , we believe that the Transmission Vegetation Management Program should be focused on removal of incompatible vegetation from the Active Right of Way.R1.1 could read: Specify the methodologies that the Transmission Owner uses to control vegetation and demonstrate that the removal of non-compatible vegetation is a focus within the plan. Incompatible vegetation should be defined as any vegetation which has the potential to grow tall enough to jeopardize the integrity of an applicable transmission line by growing into the Critical Clearance Zone or falling into the Critical Clearance Zone . This would provide clear guidance to all stakeholders, support long term vegetation management philosophies, and complement methods such as IVM where incompatible vegetation is completely removed, and compatible vegetation is encouraged to proliferate, thereby helping to control incompatible vegetation in an environmentally positive manner.
Response: Thank you for your comments. The SDT has re-written this Requirement to address your concerns in a manner that allows transmission owners flexibility in developing their Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1. Moreover, we believe the Standard as subsequently revised provides flexibility for Transmission Owners to develop their own vegetation management programs.		
Western Area Power Administration, Upper Great Plains Region	Agree	A question that has surfaced during discussions within the industry is "Can the Transmission Owner designate an active R/W width that is less than the easement width even with a single-circuit line with no R/W set aside for vegetation buffer or future development?" OR, does the easement width equate to "Active T-Line ROW" under the situation described above.
Response: Thank you for your comment. The intent of the Standard is that such rights-of-way as identified in your response are considered as "active transmission rights-of-way" in general for their full width. The definition of "active transmission line right-of-way" was developed to recognize that in some cases additional ROW width was secured to allow for buffers and future expansion. This is further described in the technical reference document.		
Western Utility Arborists	Agree	Yes, we agree, subject to the qualification about "active" rights-of-way under Comment #16. Under R1.1, it says "Specify the methodologies that the Transmission Owner uses to control vegetation." The single word "methodologies" does not adequately replace "objectives, practices, approved procedures, and work

Organization	Agree?	Question 3 Comment
		specifications." The Western Utilities recommends keeping the original wording. We would also like to point out that the original intent of the standard was to ensure that utilities had a complete vegetation management program. The new standard is evolving towards an outage control program, and no longer encourages programs or behaviors that would ensure the causes of outages are prevented long before they become a problem. The standard now redirects efforts to avoiding outages instead of managing vegetation.
Response: Thank you for your comments. The SDT has re-written this Requirement to address your concerns in a manner that allows transmission owners flexibility in developing their Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1. Moreover, we believe the Standard as subsequently revised provides flexibility for Transmission Owners to develop their own vegetation management programs. The SDT believes that the latest draft includes Requirements that dictate appropriate behavior in controlling vegetation but also added a strong statement that outages, that could have been prevented, are inconsistent with interconnection reliability and should be violations.		
Southern California Edison Company	Agree	Q3: No Comments.
Response: Thank you for your response.		
FirstEnergy	Agree	The Inactive Right of Way, by definition, should include a strip of trees on each side of the of the right of way that was purchased, but not cleared at the time of construction. This could be a narrow strip ten feet on each side that is intended for future hazard tree removal.
Response: Thank you for your comment. The definition of "Active Transmission Line Right-of-Way" has been modified in the current draft of the Standard. The SDT believes that the definition of "Active Transmission Line Right-of-Way" as currently defined is appropriate. The definition was developed to recognize that in some cases additional ROW width was secured to allow for buffers and future expansion. This is further described in the technical reference document. However, the SDT does not agree that a categorical "set aside" which is not active but can be is appropriate for all Transmission Owners. Rather, some Transmission Owners may want to manage the entire rights-of-way. But flexibility is permitted within the current draft.		
MRO NERC Standards Review Subcommittee	Agree	The MRO agrees but requests further clarification on the definition of the term "Active" in Active Transmission Line R.O.W. For example: A utility has a 150 foot easement for a 230kV line and currently manages 80 feet. First; is it the intent of the standard that the utility manage the entire 150 foot easement? Second; is the entire easement considered the Active Transmission Line R.O.W?
Response: Thank you for your comment. The Transmission Owner is responsible for determining the Active ROW width based upon the definition of "active transmission line right-of-way" included in the Standard. The scenario presented in your comment does not provide enough information for the		

Organization	Agree?	Question 3 Comment
SDT to provide a definitive answer. The definition of "Active Transmission Line Right-of-Way" has been changed in the most current draft. In addition a technical reference document with a more detailed explanation of this topic will be issued with the next draft. These documents should provide clarity. The definition was developed to recognize that in some cases additional ROW width was secured to allow for buffers and future expansion. This is further described in the technical reference document. However, the SDT does not agree that a categorical "set aside" which is not active but can be is appropriate for all Transmission Owners. Rather, some Transmission Owners may want to manage the entire rights-of-way. But flexibility is permitted within the current draft.		
ITC HOLDINGS	Agree	The standard doesn't actually explain or define the Active Transmission Line Right of Way.
Response: Thank you for your comment. A definition of "Active Transmission Line ROW" is included in the Standard. This definition has been modified in the most current draft of the Standard. The technical reference will provide further clarity.		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 3
Response: Thank you for your comment.		
American Electric Power (AEP)	Agree	While Requirement R1 does not actually define "Active Transmission Line Right of Way" (it is defined on page 2 of the Standard), AEP concurs with R1, except as noted below for R1.4.
Response: Thank you for your comment.		
Platte River Power Authority	Agree	The list of terms, "objectives, practices, approved procedures and work specifications," from version 1 provides more clarity that the one word "methodology" and should both be replaced. The newly defined term "active transmission line ROW" provides clarity to the portion of the ROW requiring vegetation management and is a valuable addition to the standard.
Response: Thank you for your comment. The SDT revised R1.1 to allow transmission owners the necessary flexibility in developing their Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1.		
American Transmission Company	Agree	We agree with the idea but the term "active transmission facilities" needs additional clarity. This clarity could be accomplished with a footnote. Proposed Footnote: A transmission facility that contains a transmission line to which FAC-003 is applicable. The proposed footnote aids in the identification of applicable transmission facilities.
Response: Thank you for your comment. Applicable lines are defined in Section 4 of the Standard.		

Organization	Agree?	Question 3 Comment
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	My disagreement with R1
Response: Thank you for your comment; however the SDT does not understand your comment.		
National Grid	Agree	Defining "Active Transmission Line Right-of-Way" solves the Right-of-Way definition problem within the SAR.
Response: Thank you for your comment.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	Yes, we agree, subject to the qualification about “active” rights-of-way under Comment #16. We would also like to point out that the original intent of the standard was to ensure that utilities had a complete vegetation management program. The new standard is evolving towards an outage control program, and no longer encourages programs or behaviors that would ensure the causes of outages are prevented long before they become a problem. Instead, it redirects efforts to avoiding outages instead of managing vegetation. If this is now the preferred approach, the term Transmission Vegetation Management Program is no longer valid and should perhaps be changed to the Transmission Vegetation Outage Prevention Program. Under R1.1, it says “Specify the methodologies that the Transmission Owner uses to control vegetation.” The single word “methodologies” does not adequately replace “objectives, practices, approved procedures, and work specifications.” We recommend that the SDT retain the original wording.
Response: Thank you for your comments. The SDT revised R1.1 to allow transmission owners the necessary flexibility in developing their Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1. The SDT believes that the latest draft includes Requirements that dictate appropriate behavior in controlling vegetation but also added a strong statement that outages, that could have been prevented, are inconsistent with interconnection reliability and should be violations.		
San Diego Gas & Electric	Agree	Yes, we agree, subject to the qualification about "active" rights of way under comment 16. Under R1.1 it says "Specify the methodologies that the Transmission Owner uses to control vegetation." The single word "methodologies" does not adequately replace "objectives, practices, approved procedures, and work specifications." We recommend keeping the original wording.
Response: Thank you for your comment. The SDT revised R1.1 to allow transmission owners the necessary flexibility in developing their Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1.		
Northeast Utilities	Agree	With respect to "active transmission line ROW" the examples provided in the Technical Reference document for FAC-003-2 show that any areas of the easement or fee-owned right-of-way not cleared in accordance with

Organization	Agree?	Question 3 Comment
		company approved design standards will not be considered "active transmission line ROW". Any vegetation contacts resulting from trees that fail in these non-cleared sections ("corridor edge zones") would not constitute a violation of FAC-003-2.The definition of the "active transmission line right-of-way" states that this does not include areas of the easement or fee-owned property that is unused or inactive and intended for other facilities. Does this imply that areas not cleared and not intended for other facilities are part of the active right-of-way? If a company had constructed new lines and allowed for a buffer strip of the easement that was not cleared, but is also not intended for new facilities, and trees are allowed to remain in this strip - that an outage from contact with a tree falling into the lines from this buffer would constitute a violation of R7 as a tree falling from within the active right-of-way? Does this imply that trees in these buffer strips must be removed? This will constitute a very costly and problematic position that will result in extreme adverse public opposition to the required clearing. It is suggested that the clearing limits of any right-way comply with some established standards or codes. A utility should not be allowed to eliminate a large number of vegetation violations by simply decreasing the size or width of the active right-of-way. However, this may also need to be flexible when new lines are constructed when easement widths are limited due to local or state requirements.
Response: Thank you for your comments. The definition of "Active Transmission Line Right-of-Way" has been modified in the current draft of the Standard. The SDT believes that the definition of "Active Transmission Line Right-of-Way" as currently defined is appropriate. The definition was developed to recognize that in some cases additional ROW width was secured to allow for buffers and future expansion. This is further described in the technical reference document. The new section in the technical reference attempts to address these issues.		
Buckeye Power, Inc.	Agree	OK with R1. However, the active transmission line right of way seems to be a reduction in ROW width which would likely decrease reliability during the one moment when we need it most.
Response: Thank you for your comment. The "active transmission line right-of-way" definition has been developed to address rights-of-way obtained for future facilities. It is not intended to diminish the Transmission Owners' responsibility to manage vegetation on a right-of-way which was acquired solely for the purpose of the subject line and is necessary for the reliable operation of the line.		
Great River Energy	Agree	GRE agrees but requests further clarification on the definition of the term "Active" in Active Transmission Line R.O.W. For example: A utility has a 150 foot easement for a 230kV line and currently manages 80 feet. First; is it the intent of the standard that the utility manage the entire 150 foot easement? Second; is the entire easement considered the Active Transmission Line R.O.W?
Response: Thank you for your comment. The Transmission Owner is responsible for determining the Active ROW width based upon the definition of "active transmission line right-of-way" included in the Standard. The scenario presented in your comment does not provide enough information for the SDT to provide a definitive answer. The definition of "Active Transmission Line Right-of-Way" has been changed in the most current draft. In addition a technical reference document with a more detailed explanation of this topic will be issued with the next draft. These documents should provide clarity.		

Organization	Agree?	Question 3 Comment
BCTC	Agree	Yes, we agree, subject to the qualification about “active” rights-of-way under Comment #16. We would also like to point out that the original intent of the standard was to ensure that utilities had a complete vegetation management program. The new standard is evolving towards an outage control program, and no longer encourages programs or behaviours that would ensure the causes of outages are prevented long before they become a problem. Instead, it redirects efforts to avoiding outages instead of managing vegetation. If this is now the preferred approach, the term Transmission Vegetation Management Program is no longer valid and should perhaps be changed to the Transmission Vegetation Outage Prevention Program. Under R1.1, it says “Specify the methodologies that the Transmission Owner uses to control vegetation.” The single word “methodologies” does not adequately replace “objectives, practices, approved procedures, and work specifications.” BCTC recommends keeping the original wording.
Thank you for your comments. The SDT revised R1.1 to allow transmission owners the necessary flexibility in developing their Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1. The SDT believes that the latest draft includes Requirements that dictate appropriate behavior in controlling vegetation but also added a strong statement that outages, that could have been prevented, are inconsistent with interconnection reliability and should be violations.		
WECC Reliability Coordination	Agree	
SERC Vegetation Management Subcommittee (VMS)	Agree	
Progress Energy Florida	Agree	
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Progress Energy Carolinas	Agree	
SERC OC Standards Review Group	Agree	

Organization	Agree?	Question 3 Comment
Florida Power & Light	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	
SERC Compliance Staff	Agree	
Exelon	Agree	
Central Maine Power Company	Agree	
City of Tallahassee	Agree	
Northern California Power Agency (NCPA)	Agree	
Tampa Electric Company	Agree	
Orange and Rockland Utilities Inc.	Agree	
Ameren	Agree	
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Manitoba Hydro	Agree	

Organization	Agree?	Question 3 Comment
Consumers Energy Company	Agree	
Pacific Gas & Electric Co.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Arizona Public Service Company	Agree	
Duke Energy Corporation	Agree	
Entergy Services	Agree	
Pepco Holdings, Inc	Agree	

4. **Documentation and implementation of the transmission vegetation management program which were previously combined in Requirement R1 are now separated in order to apply appropriate VRFs and time horizons. The implementation of some elements has been moved into standalone requirements such as inspection cycles (R3) and annual plan implementation (R9). Do you agree with these revisions and separation? If not, please explain.**

Summary Consideration: Most respondents were in favor of separating the documentation from the implementation. A minority of the respondents wanted to keep the two together. The SAR directed the team to bring the standard into conformance with the latest version of the Sanctions Guidelines. Retention of documentation to demonstrate compliance is now addressed, in most cases, solely in the "Data Retention" section of standards and does not need to be covered in requirements. If an entity does not retain data and there is no impact to reliability, then the retention of that data, if needed to demonstrate compliance, is covered under the Data Retention section.

Some respondents advocated modifying the order or sequence of the standard's requirements. The SDT has considered various sequence options and offers a re-sequencing proposal as Question #12 in the second Comment Form.

Organization	Agree?	Question 4 Comment
BCTC		Although it's important to have these two separate aspects – documentation and implementation – separating them spatially in the document itself makes the standard longer than necessary and creates redundancy. It seems obvious that if you prepare elements of the Transmission Vegetation Management Program, they also need to be implemented. The document would be easier to follow if the two elements were kept together.
Response: The SDT thanks you for your comments. The SDT determined that the requirements to document and implement are distinctly different activities and therefore separated them. Having separate requirements allows for assignment of VRF's and VSL's that more closely reflect their respective characteristics. The SDT has considered various sequence options and offers a re-sequencing proposal as Question #12 in the second Comment Form.		
Western Utility Arborists		Although it's important to have these two separate aspects "documentation and implementation "separating them spatially in the document itself makes the standard longer than necessary and creates redundancy. It seems obvious that if you prepare elements of the Transmission Vegetation Management Program, they also need to be implemented. The document would be easier to follow if the two elements were kept together.
Response: The SDT thanks you for your comments. The SDT determined that the requirements to document and implement are distinctly different activities and therefore separated them. Having separate requirements allows for assignment of VRF's and VSL's that more closely reflect their respective characteristics. The SDT have considered various sequence options and offer a re-sequencing proposal as Question #12 in the second		

Organization	Agree?	Question 4 Comment
Comment Form.		
Progress Energy Florida	Disagree	The sub-requirements should be moved up to requirement level if the team desires to have different VRFs and VSLs.
Response: The SDT thanks you for your comments. The Standards drafting team has dropped the sub requirement designations and the sub parts are simply listed as part of R1.		
Progress Energy Carolinas	Disagree	The sub-requirements should be moved up to requirement level if the team desires to have different VRFs and VSLs.
Response: The SDT thanks you for your comments. The Standards drafting team has dropped the sub requirement designations and the sub parts are simply listed as part of R1.		
Southern California Edison Company	Disagree	Q4: SCE does not agree with separating the documentation and implementation aspects of the Transmission Vegetation Management Program into separate requirements R3 and R9 (respectively). SCE believes that proposed R3 and corresponding M3 should be eliminated and replaced with a modified version of proposed R9. SCE respectfully suggests that proposed R9 be revised to read: "Each Transmission Owner shall implement and follow its Vegetation Management Program to the extent allowed by existing easement and/or legal rights."
Response: The SDT thanks you for your comments. The team believes that conducting inspections is independently important and therefore should be addressed in a separate requirement. The SDT debated the issue of whether to include "Each Transmission Owner shall implement and follow its Vegetation Management Program to the extent allowed by existing easement and/or legal rights". The final consensus of the SDT was to exclude the requirement because having the legal rights do not imply one is obligated to exercise those rights to their fullest extent. The SDT did not want to give that impression.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Disagree	Although it's important to have these two separate aspects " documentation and implementation " separating them spatially in the document itself makes the standard longer than necessary and creates redundancy. It seems obvious that if you prepare elements of the Transmission Vegetation Management Program, they also need to be implemented. The document would be easier to follow if the two elements were kept together.
Response: The SDT thanks you for your comments. The SDT determined that the requirements to document and implement are distinctly different activities and therefore separated them. Having separate requirements allows for assignment of VRF's and VSL's that more closely reflect their respective characteristics. The SDT have considered various sequence options and offer a re-sequencing proposal as Question #12 in the second Comment Form.		

Organization	Agree?	Question 4 Comment
San Diego Gas & Electric	Disagree	The document would be easier to follow if kept together. Separation of the recommendations and implementation will make this a redundant process, because both will say the same thing.
Response: The SDT thanks you for your comments. The SDT determined that the requirements to document and implement are distinctly different activities and therefore separated them. Having separate requirements allows for assignment of VRF's and VSL's that more closely reflect their respective characteristics. The SDT considered other sequence options and offer a re-sequencing proposal as Question #12 in the second Comment Form.		
JEA	Disagree	See comment from #3.
Response: The SDT thanks you for your comments. See response to Q #3.		
Salt River Project	Disagree	Although we agree that it is important to identify both aspects of the program for "prepare/documentation" and "implementation", we do not agree that this needs to be documented in separate requirements. It makes the standard longer than necessary and creates redundancy. The document would be easier to follow if the two elements were kept together in the same requirement. In addition, it is not defined what is "VRFs". We understand that this was detailed in a previous draft document as "Violation Risk Factor". This needs to be defined and clarified in order to provide comment back.
Response: The SDT thanks you for your comments. The SDT determined that the requirements to document and implement are separate and require different levels of VRF's and VSL's. The team refers you to the *Sanction Guidelines of North American Electric Reliability Corporation* to explain the use of VRF's and VSL's.		
CenterPoint Energy	Disagree	Additional revisions are needed to clarify the requirements. For instance, R1.3 refers to "the objectives" of the Transmission Vegetation Management Program, which are no longer a required element and are not specified in M1.3. Reference to "the objectives" should be deleted. The last sentence of R1.3 should read: "It shall use the methodologies outlined in the transmission vegetation management program."R1.4 requires a process for a response to an "imminent threat of a vegetation related Sustained Outage", but R2 refers to implementing an "imminent threat procedure" to "prevent an encroachment of the Critical Clearance Zone". The requirement and the implementation should both refer to an "imminent threat of a vegetation related Sustained Outage".
Response: The SDT thanks you for your comments. The team is posting a revised standard and R1 identifies the required elements of the Transmission Vegetation Management Program. The sub requirements have been changed to elements that roll up into R1 and an additional element has been added to cover methods used to control vegetation – the word, "objectives" is not used in the revised standard.		
MRO NERC Standards Review	Agree	The MRO believes that clarity was improved by separating documentation and implementation. The MRO

Organization	Agree?	Question 4 Comment
Subcommittee		suggests that moving the requirement for implementation so that it immediately follows the requirement for documentation will further enhance clarity.
Response: The SDT thanks you for your comments. The SDT has considered various sequence options and offers a re-sequencing proposal as Question #12 in the second Comment Form.		
Midwest ISO Stakeholders Standards Collaborators	Agree	This is a good change from a compliance perspective; the documentation requirements can now be assigned lower VRFs than the implementation requirements.
Response: The SDT thanks you for your comments.		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 4
Response: The SDT thanks you for your comments.		
Exelon	Agree	Refer to footnotes in R1.1 and 1.2. Are applicable entities to be held accountable to ANSI A300 (footnote 2) and for providing documentation to support analysis that "local factors" were accounted for (footnote 3)? These footnotes should be requirements or they should be removed and included in a Reference Document not subject to compliance audit.
Response: The SDT thanks you for your comments. Please note the phrase in the current version of footnote 2," while not a requirement of this standard." A300 is a recommended best practice and not a requirement. Footnotes may be used to provide explanatory information.		
American Electric Power (AEP)	Agree	AEP agrees with these changes from Version 1.
Response: The SDT thanks you for your comments.		
Platte River Power Authority	Agree	The separation allows lower sanctions and penalties to be assessed for weak documentation and higher sanctions and penalties to be assessed for weak inspection programs and weak vegetation management. However, the standard would be easier to follow if the two elements were kept together in the document.
Response: The SDT thanks you for your comments. The SDT determined that the requirements to document and implement are separate and require different levels of VRF's and VSL's. The SDT has considered various sequence options and offers a re-sequencing proposal as Question #12 in the second Comment Form.		
City of Tallahassee	Agree	See Question 6 and 17.

Organization	Agree?	Question 4 Comment
Response: The SDT thanks you for your comments. See the responses to Questions 6 and 17.		
Northern Indiana Public Service Company	Agree	I agree with the separation and re-ordering of documentation and implementation requirements into two distinct groups. This is a welcome improvement to the standard.
Response: The SDT thanks you for your comments. The SDT has considered various sequence options and offers a re-sequencing proposal as Question #12 in the second Comment Form.		
National Grid	Agree	These revisions and separation make it easier to match requirements and measures.
Response: The SDT thanks you for your comments.		
Ameren	Agree	This is a good change from a compliance perspective; the documentation requirements can now be assigned lower VRFs than the implementation requirements
Response: The SDT thanks you for your comments.		
Duke Energy Corporation	Agree	This is a good change from a compliance perspective; the documentation requirements can now be assigned lower VRFs than the implementation requirements.
Response: The SDT thanks you for your comments		
Great River Energy	Agree	GRE believes that clarity was improved by separating documentation and implementation. GRE suggests that moving the requirement for implementation so that it immediately follows the requirement for documentation will further enhance clarity
Response: The SDT thanks you for your comments. The SDT has considered various sequence options and offers a re-sequencing proposal as Question #12 in the second Comment Form.		
Associated Electric Cooperative Inc.	Agree	
NPCC	Agree	
WECC Reliability Coordination	Agree	

Organization	Agree?	Question 4 Comment
Western Area Power Administration, Upper Great Plains Region	Agree	
SERC Vegetation Management Subcommittee (VMS)	Agree	
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
SERC OC Standards Review Group	Agree	
Florida Power & Light	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
Bonneville Power Administration	Agree	
FirstEnergy	Agree	
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	
Central Maine Power Company	Agree	
Northern California Power Agency	Agree	

Organization	Agree?	Question 4 Comment
(NCPA)		
Tampa Electric Company	Agree	
Orange and Rockland Utilities Inc.	Agree	
American Transmission Company	Agree	
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	
Manitoba Hydro	Agree	
Consumers Energy Company	Agree	
Pacific Gas & Electric Co.	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Arizona Public Service Company	Agree	
Baltimore Gas & Electric Company	Agree	

Organization	Agree?	Question 4 Comment
Entergy Services	Agree	
Pepco Holdings, Inc	Agree	
Independent Electricity System Operator	Agree	
Northeast Utilities	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
Buckeye Power, Inc.	Agree	

5. In R1.2 the Transmission Owner is required to have an inspection frequency of at least once per calendar year. Do you agree with R1.2? If not, please explain.

Summary Consideration: The majority of the respondents were in favor of the one year frequency. Most of the minority commenters wanted to leave the decision with the Transmission Owner. Since vegetation inspections can be included in overhead maintenance inspections, the SDT did not consider the annual inspection requirement to be burdensome. Several commenters asked for a definition of “inspection” and the SDT is proposing the following modification to an existing NERC Glossary definition of “Vegetation Inspection:”

Vegetation Inspection: The systematic examination of vegetation conditions on an Active Transmission Line Right of Way. This inspection may be combined with a general line inspection. The inspection includes the documentation of any vegetation that may pose a threat to reliability prior to the next planned inspection or maintenance work, considering the current location of the conductor and other possible locations of the conductor due to sag and sway for rated conditions.

Organization	Agree?	Question 5 Comment
BCTC		Clarification is required on exactly what an inspection is, which should perhaps be outlined in the white paper. At BCTC although all lines are currently inspected at least once every year the thoroughness of the inspection will vary with the local conditions. Some areas with limited vegetation management issues only require a patrol from the air and are often inspected as part of a routine line patrol, where the lineman looks for vegetation concerns in addition to undertaking maintenance work. Other areas require a detailed ground inspection. BCTC needs some assurance that this inspection will not constitute a dedicated, comprehensive vegetation management inspection of the entire operating system. . Therefore, BCTC needs the ability within the Transmission Vegetation Management Program to define what an inspection is in the context of our utility operations.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections. The SDT revised the NERC glossary term Vegetation Inspection to allow it to be combined with other line inspections.		
Western Utility Arborists		Clarification is required on exactly what an inspection is, which should perhaps be outlined in the white paper. There are areas where inspections are not necessary at all, such as lines over a parking lot, or in a remote desert area. The Western Utilities need some assurance that this inspection will not constitute a dedicated, comprehensive vegetation management inspection. Inspections are currently often part of a routine line patrol, where the lineman looks for

Organization	Agree?	Question 5 Comment
		vegetation concerns in addition to undertaking maintenance work. Therefore, the Transmission Owner needs the ability within their Transmission Vegetation Management Program to define what an inspection is in the context of their utility operations.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections. The SDT revised the NERC glossary term Vegetation Inspection to allow it to be combined with other line inspections.		
Associated Electric Cooperative Inc.	Disagree	While Associated Electric Cooperative Inc agrees with this requirement in general, there may be areas (e.g. highly arid terrain, open water, etc.) where an annual interval is unnecessary and adds little or nothing to reliability.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		
NPCC	Disagree	There were differing opinions within the group. Those entities with extensive overhead transmission felt the once a year requirement was overly prescriptive and would not improve reliability, others were in agreement with the "at least once per calendar year" requirement.
Response: The SDT thanks you for your comments. The consensus of the SDT is that annual inspections add to the reliability of the system.		
Tennessee Valley Authority	Disagree	TVA suggests that R1.2 be changed by adding "except in cases where lines or significant sections of lines are over terrain which is void of vegetation(such as bodies of deep water)or over terrain void of any vegetation that can grow to a mature height that could threaten the conductors, then longer cycles will be acceptable". This would avoid unnecessary expenses in such cases.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		
Western Area Power Administration, Rocky Mountain Region	Disagree	Some areas such as highly developed urban areas, deserts, or grassland prairie may not be conducive to tall vegetation growth and require frequent (annual) inspection.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		

Organization	Agree?	Question 5 Comment
Southern California Edison Company	Disagree	Q5: SCE does not agree with imposing a one-size-fits-all inspection frequency of ?at least once per calendar year? upon all U.S. Transmission Owners. The associated technical paper presents no credible evidence or statistical corroboration to support the proposed inspection frequency. Until such time as a thorough industry study or similar evidence is presented that demonstrates the proposed inspection frequency is cost effective and will enhance system reliability, Transmission Owners should be allowed to establish their own inspection frequency rate. Regarding the enforcement of a non-standardized inspection frequency, should a Transmission Owner incur a vegetation-to-line contact that results in a Sustained Outage, upon review of the investigation results, the responsible Reliability Coordinator and/or NERC could then impose a more stringent inspection frequency requirement upon the infracting Transmission Owner. The imposition of more stringent inspection frequencies could be applied on a temporary or permanent basis, depending on the severity of the outage, but lacking a demonstrated need, good performing Transmission Owners should be allowed to establish their own inspection frequencies based upon their individual needs and operating conditions. SCE respectfully suggests R1.2 be revised to read: "Specify a vegetation inspection frequency that takes into account local and environmental factors."
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		
SERC OC Standards Review Group	Disagree	While the SERC OCSRG agrees with this requirement in general, there may be areas (e.g., desert terrain) where an annual interval would be unnecessary and not cost effective.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		
City of Tallahassee	Disagree	While TAL's specific conditions and current process would meet this requirement, I can envision where some conditions may not require an annual inspection. These might include desert conditions, crop fields, over water, etc. To dictate a specific one-year requirement could be burdensome to some utilities with no improvement to the reliability of the BES.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		
Xcel Energy	Disagree	Add a note of exception to the requirement for inspections on those lines that do not have vegetation management issues (e.g. lines that traverse desert areas only).
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done		

Organization	Agree?	Question 5 Comment
annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Disagree	It would seem also that the T.O. should be expected to react to circumstances that create the need for a more frequent inspection cycle such as conditions that cause widespread vegetation mortality such as drought and/or beetle infestations.
Response: The SDT thanks you for your comments. The standard does restrict the number of inspections and does require the Transmission Owner to examine the local and environmental conditions that might require a greater frequency.		
Consumers Energy Company	Disagree	FERC required NERC in Order 693 to develop appropriate inspection cycles based on local factors. Potential annual tree growth varies considerably within the geography of the United States and FAC-003-1 recognized this factor and left it up to the utility to determine the most appropriate inspection cycle for their system. This was in lieu of having proper data readily available to determine inspection cycles for various areas that could be incorporated into the standard. FAC-003-2 greatly decreases the minimum separation distance between conductors and vegetation. Table 1 shows the minimum distance at sea level for a 345 kV line a 3.12 feet. This is considerably less than the potential annual growth rate of many tree species in many areas of the United States. Therefore, the annual inspection cycle would not be acceptable to identify tree growth that can violate the minimum distance before it occurs. Consumers Energy strongly believes that using the Gallet formula to determine the minimum clearance between conductors and vegetation will decrease the reliability of the system compared to the minimum clearance requirements in FAC-003-1.
Response: The SDT thanks you for your comments. The consensus of the SDT is that the frequency of inspection does not drive the minimum clearance the Transmission Owner operates from. The SDT would expect the minimum clearance to be driven by growth rate and maintenance frequency.		
National Grid	Disagree	R1.2, M1.2 and M1.3 in the Standard all refer to calendar year. National Grid objects to inspections being based on a calendar year. Transmission Owners should be able to define their own "year". (See Question No. 18.)
Response: The SDT thanks you for your comments. By using "once per calendar year" the standard does not confine the inspection to a specific date. This improves flexibility in the inspection schedule.		
Hydro One Networks Inc.	Disagree	Clarification is required on the requirements. The frequency and need for inspection is based on a number of factors that include: type of vegetation on a right of way, change in growing conditions and the Transmission Owner's clearance standards (i.e., if the clearance standards are well above the Critical Clearance then the risk to reliability may be very low, so why inspect for vegetation clearances on an annual basis?) This being the case, clarification is needed on inspection requirements relative to the overall approach used to manage vegetation clearances. For example, Hydro One conducts routine line inspections on an annual basis and identifies clearance issues. Would this

Organization	Agree?	Question 5 Comment
		meet the requirements of the standard?
Response: The SDT thanks you for your comments. Yes. The SDT added a definition for Vegetation Inspection to the standard.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Disagree	Clarification is required on exactly what an inspection is, which should perhaps be outlined in the white paper. There are areas where inspections are not necessary at all, such as lines over a parking lot, or in a remote desert area. We need some assurance that this inspection will not constitute a dedicated, comprehensive vegetation management inspection. Inspections are currently often part of a routine line patrol, where the lineman looks for vegetation concerns in addition to undertaking maintenance work. Therefore, the Transmission Owner needs the ability within their Transmission Vegetation Management Program to define what an inspection is in the context of their utility operations.
Response: The SDT thanks you for your comments. The SDT added a definition for Vegetation Inspection to the standard.		
CenterPoint Energy	Disagree	The Standard and the Technical Reference provide no specific justification for defining a 1-year inspection frequency and is arbitrary. The requirement itself does not take into account "local and environmental factors". Since the type of inspection is not specified within the Standard, a frequency of at least once per calendar year is currently workable for CenterPoint Energy, but it may not necessarily be appropriate for Transmission Owners with sparsely vegetated service territories. The Technical Reference for R1.2 should state, "the Transmission Owner is given discretion as to the inspection method", and "that while the inspection frequency is specified, it is not the intent of the Standard that all vegetation be maintained on the same frequency". For example, CenterPoint Energy currently utilizes a 5-year ground-based inspection cycle coupled with a 5-year cycle for vegetation maintenance, and performs a supplemental annual aerial inspection.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations and this is explained in the Technical Reference. Vegetation inspections can be included in overhead maintenance inspections. The SDT added a definition for Vegetation Inspection to the standard which would work provided you do your annual flight.		
Alberta Electric System Operator	Disagree	The AESO believes that the inspection schedule should consider local and environmental factors that may impact the anticipated growth rate of vegetation. In many of the areas in Alberta, due to cold climate and arid conditions, we have slow vegetation growth rates. The requirement for minimum annual inspection is not necessary. We recommend the inspection schedule be determined by the Transmission Owner and documented in its vegetation management plan.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done at		

Organization	Agree?	Question 5 Comment
least annually to cover both engineering and vegetation situations. A more frequent cycle may specified by the Transmission Owner to account for local conditions. Slow growth rates, arid conditions etc. which may render an annual frequency unnecessary for Vegetation Inspections can be included in overhead maintenance inspections.		
Pepco Holdings, Inc	Disagree	While an annual inspection is reasonable and appropriate for all but very low precipitation areas, In Order 693, the Commission directs the ERO to develop compliance audit procedures, using relevant industry experts, which would identify appropriate inspection cycles based on local factors. The SDT does not seem to have taken the local factors into account. FERC also does not want to leave this up to the Transmission Owners. While the standards being developed are moving many things to the RC, PHI sees that as the only way to have someone other than the Transmission Owner determine an inspection cycle that would consider local factors.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done at least annually to cover both engineering and vegetation situations. A more frequent cycle may specified by the Transmission Owner to account for local conditions. Slow growth rates, arid conditions etc. which may render an annual frequency unnecessary for Vegetation Inspections can be included in overhead maintenance inspections.		
Hydro-Quebec Transenergie (HQT)	Disagree	The frequency and need for inspection is based on a number of factors that include: type of vegetation on a right of way, rainfall during any given year, climate (very slow growth in nordic area), when the last removal of vegetation was done, etc. HQT believes R1.2 is overly prescriptive when a “at least once a year” becomes mandatory; these terms should be removed from the Standard.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done at least annually to cover both engineering and vegetation situations. A more frequent cycle may specified by the Transmission Owner to account for local conditions. Slow growth rates, arid conditions etc. which may render an annual frequency unnecessary for Vegetation Inspections can be included in overhead maintenance inspections.		
Bonneville Power Administration	Agree	It would be helpful to clarify what is expected in regards to what constitutes an inspection. This could be done in the technical reference. Some Transmission Operators inspect vegetation as part of line patrol that focuses on more than just the condition of vegetation along the Right of Way. It should be clear that the Transmission Owner, though required to complete a inspection frequency of at least once per calendar year, has the ability to implement the type of inspection it deems necessary. Also the frequency of once per calendar year may create some unintended reporting difficulties if Transmission Owners currently track progress and completion of inspections using a different convention than calendar year, e.g., fiscal year or other period. It may be helpful to change the wording of R1.2 from "at least once per calendar year" to "once in a twelve month period."
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done		

Organization	Agree?	Question 5 Comment
annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		
MRO NERC Standards Review Subcommittee	Agree	The MRO suggests rewording the requirement to remove ". and environmental" . The MRO believes that local factors includes environmental.
Response: The SDT thanks you for your comments. The SDT considers local conditions to account for design and operating situation and environmental includes both the normal expected environmental conditions and changes from the norm such as drought major storms, fire etc.		
SERC Vegetation Management Subcommittee (VMS)	Agree	While the SERC VMS agrees in general, there may be areas (i.e. desert terrain) where an annual interval would be unnecessary and not cost effective.
Response: The SDT thanks you for your comments. The consensus of the SDT is that annual inspections add to the reliability of the system.		
American Electric Power (AEP)	Agree	AEP agrees with this change.
Response: The SDT thanks you for your comments.		
Platte River Power Authority	Agree	The inspection frequency is reasonable.
Response: The SDT thanks you for your comments.		
American Transmission Company	Agree	We agree with a minimum inspection frequency, but believe that the additional verbiage "? that takes into account local and environmental factors" should be deleted. The additional verbiage does not provide greater reliability only more documentation. Proposed Language: Specify a vegetation inspection frequency of at least once per calendar year.
Response: The SDT thanks you for your comments. The consensus of the SDT is that local and environmental factors might demand a greater frequency than once per calendar year and vegetation inspections can be included in overhead maintenance.		
Arizona Public Service Company	Agree	Clarification is required on exactly what an inspection is, which should perhaps be outlined in the white paper. There are areas where inspections are not necessary at all, such as lines over a parking lot, or in a remote desert area. APS needs some assurance that this inspection will not constitute a dedicated, comprehensive vegetation management inspection. Inspections are currently often part of a routine line patrol, where the forester or lineman looks for vegetation concerns in addition to undertaking maintenance work. Therefore, the Transmission Owner needs the

Organization	Agree?	Question 5 Comment
		ability within their Transmission Vegetation Management Program to define what an inspection is in the context of their utility operations.
Response: The SDT thanks you for your comments. The SDT added a definition for Vegetation Inspection to the standard.		
Pacific Gas & Electric Co.	Agree	This requirement is appropriate to ensure adequate inspection frequencies, however, a clear definition of "inspection" should be contained in either the standard or white paper.
Response: The SDT thanks you for your comments. The SDT added a definition for Vegetation Inspection to the standard.		
JEA	Agree	Although there are probably few areas where this is appropriate, the entity should be able to reduce the required number of inspections with RC approval if they are able to demonstrate that vegetation conditions surrounding transmission lines does not warrant inspections at that frequency.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		
Salt River Project	Agree	The Transmission owner needs the ability to define what an inspection is in the context of their utility operation. Inspections may not constitute a dedicated, comprehensive vegetation management inspection, but could often be part of a routine line patrol, where linemen or engineers look for vegetation concerns in addition to undertaking maintenance work. Clarification of that would be helpful, suggest that could be documented in the Technical Reference document.
Response: The SDT thanks you for your comments. The SDT added a definition for Vegetation Inspection to the standard.		
Great River Energy	Agree	GRE suggests rewording the requirement to remove ". and environmental" . GRE believes that local factors takes into account environmental.
Response: The SDT thanks you for your comments. The SDT considers local conditions to account for design and operating situation and environmental includes both the normal expected environmental conditions and changes from the norm such as drought major storms, fire etc.		
San Diego Gas & Electric	Agree	The term "inspection" needs to be better defined, as well as the term "calendar year."

Organization	Agree?	Question 5 Comment
Progress Energy Carolinas	Agree	
Florida Power & Light	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
Progress Energy Florida	Agree	
Kansas City Power & Light	Agree	
E.ON U.S.	Agree	
FirstEnergy	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	
Exelon	Agree	
Central Maine Power Company	Agree	

Organization	Agree?	Question 5 Comment
Northern California Power Agency (NCPA)	Agree	
Northern Indiana Public Service Company	Agree	
Tampa Electric Company	Agree	
Orange and Rockland Utilities Inc.	Agree	
Ameren	Agree	
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Manitoba Hydro	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Baltimore Gas & Electric Company	Agree	
Duke Energy Corporation	Agree	
Entergy Services	Agree	

Organization	Agree?	Question 5 Comment
Independent Electricity System Operator	Agree	
Northeast Utilities	Agree	
Buckeye Power, Inc.	Agree	

6. **In R1.3 the Standard requires that transmission vegetation management program specify an Annual Plan and specifies parameters for the plan. Implementation of the Annual Plan is separated and placed in R9. Do you agree with R1.3 and the separation of the implementation from the specification of the Annual Plan? If not, please explain.**

Summary Consideration: The majority of the respondents are in favor of the changes. There was a minority of the respondents that made a valid point that elements in the annual plan were lost in the posting. The SDT determined that the requirement to document and implement are separate and require different levels of VRF's and VSL's. The SDT chose a compromise wording to accommodate those points.

Organization	Agree?	Question 6 Comment
BCTC		The document would benefit from keeping the two requirements together, since they relate to the same topic. Under the new wording in R1, the Transmission Vegetation Management Program no longer has a requirement to include objectives. However, there is a phrase in R1.3 to "support the objectives…and methodologies…outlined in the…program." To be consistent with R1.3, BCTC recommends that R1.1 be reworded to specify the methodologies and objectives that the Transmission Owner uses to control vegetation.
Response: The SDT thanks you for your comments. However, the SDT determined that the requirements to document and implement should be separate and require different levels of Violation Risk Factors and Violation Severity Levels. Thus, the SDT respectfully does not adopt your suggestion to keep the two requirements together. The SDT also disagrees with returning "objectives" to R1. We do, however, agree that there exists a small dichotomy since "objectives" are no longer stated in R1 while being referenced in part 1.3. Subsequently the SDT has removed this wording from part 1.3. Further, the SDT has revised R1 to require the Transmission Owner to specifically describe how it will conduct work to comply with the Standard in lieu of requiring the Transmission Owner to only identify general objectives.		
Western Utility Arborists		The document would benefit from keeping the two requirements together, since they relate to the same topic. Under the new wording in R1, the Transmission Vegetation Management Program no longer has a requirement to include objectives. However, there is a phrase in R1.3 to "support the objectives" and methodologies "outlined in the "program." To be consistent with R1.3, the Western Utilities recommends that R1.1 be reworded to specify the methodologies and objectives that the Transmission Owner uses to control vegetation.
Response: The SDT thanks you for your comments. However, the SDT determined that the requirements to document and implement should be separate and require different levels of Violation Risk Factors and Violation Severity Levels. Thus, the SDT respectfully does not adopt your suggestion to keep the two requirements together. The SDT also disagrees with returning "objectives" to R1. We do, however, agree that there exists a small dichotomy since "objectives" are no longer stated in R1 while being referenced in part 1.3. Subsequently the SDT has removed this wording from part 1.3. Further, the SDT has revised R1 to require the Transmission Owner to specifically describe how it will conduct work to comply with the		

Organization	Agree?	Question 6 Comment
Standard in lieu of requiring the Transmission Owner to only identify general objectives.		
NPCC	Disagree	R1.2 and R1.3 should specifically state calendar year, and the Annual Plan and inspection follow the same calendar year timing.
Response: The SDT thanks you for your comments. The SDT points out that these two parts, R1.2 and R1.3, refer to different aspects of the Transmission Vegetation Management Program. Further, to assist in clarity, the SDT has revised part 1.3 and in doing so has removed the phrase "during the year" since it added no value to the requirement. The SDT does not agree with your suggestion to base the annual plan on a calendar year and feels that the Transmission Owner should retain the flexibility to determine the time period for - Requirement R1 clearly limits the scope of the TVMP to work on the entity's Active Transmission Line Rights of Way - and the "annual work plan" is one element of the overall TVMP annual plan.		
City of Tallahassee	Disagree	While I can agree with a separate requirement (R9) to implement the plan developed in R1.3, they need to both have the flexibility desired in R1.3. I do not see that flexibility in R9. See response to question 17.
Response: The SDT thanks you for your comments. R9 is the implementation of 1.3 which is flexible. The flexibility of 1.3 carries through to R9.		
Northern Indiana Public Service Company	Disagree	I disagree with the elimination of the present requirement R2 (last sentence) that requires a Transmission Owner to have proper quality control (QC) systems and procedures in place to document & track planned UVM work so as to verify it was completed properly to work specifications. The need for this requirement was demonstrated as recently as last year when a grow-in outage occurred at BG&E due to a contractor trimming the wrong tree at the wrong location, a situation that could have been prevented with effective QC.
Response: The SDT thanks you for your comments. The consensus of the SDT is that in order to implement the plan the Transmission Owner must complete its work plan to its standards. The level of QC is within the Transmission Owner's purview.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Disagree	I think that the Transmission Owner should be able to specify the effective period of the plan whether it is one year or ten years. Arizona utilities are starting to think in terms of multi-year corridor management plans. A one year planning period could be specified as the minimum planning period.
Response: The SDT thanks you for your comments. The SDT agrees that long term plans can be of value and can be done within the standard. The standard is trying to insure the immediate reliability work is budgeted and completed.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Disagree	The document would benefit from keeping the two requirements together, since they relate to the same topic. Under the new wording in R1, the Transmission Vegetation Management Program no longer has a requirement to include objectives. However, there is a phrase in R1.3 to "support the objectives" and methodologies" outlined in the "program." To be consistent with R1.3, we recommend that R1.1 be reworded to specify the methodologies and

Organization	Agree?	Question 6 Comment
		objectives that the Transmission Owner uses to control vegetation.
Response: The SDT thanks you for your comments. However, the SDT determined that the requirements to document and implement should be separate and require different levels of Violation Risk Factors and Violation Severity Levels. Thus, the SDT respectfully does not adopt your suggestion to keep the two requirements together. The SDT also disagrees with returning "objectives" to R1. We do, however, agree that there exists a small dichotomy since "objectives" are no longer stated in R1 while being referenced in part 1.3. Subsequently the SDT has removed this wording from part 1.3. Further, the SDT has revised R1 to require the Transmission Owner to specifically describe how it will conduct work to comply with the Standard in lieu of requiring the Transmission Owner to only identify general objectives.		
Arizona Public Service Company	Disagree	The document would benefit from keeping the two requirements together, since they relate to the same topic. Under the new wording in R1, the Transmission Vegetation Management Program no longer has a requirement to include objectives. However, there is a phrase in R1.3 to "support the objectives" and methodologies "outlined in the "program." To be consistent with R1.3, APS recommends that R1.1 be reworded to specify the methodologies and objectives that the Transmission Owner uses to control vegetation.
Response: The SDT thanks you for your comments. However, the SDT determined that the requirements to document and implement should be separate and require different levels of Violation Risk Factors and Violation Severity Levels. Thus, the SDT respectfully does not adopt your suggestion to keep the two requirements together. The SDT also disagrees with returning "objectives" to R1. We do, however, agree that there exists a small dichotomy since "objectives" are no longer stated in R1 while being referenced in part 1.3. Subsequently the SDT has removed this wording from part 1.3. Further, the SDT has revised R1 to require the Transmission Owner to specifically describe how it will conduct work to comply with the Standard in lieu of requiring the Transmission Owner to only identify general objectives.		
Baltimore Gas & Electric Company	Disagree	See response to question no. 17.
Response: The SDT thanks you for your comments. See response to comments on #17.		
JEA	Disagree	See comment from #3.
Response: The SDT thanks you for your comments. See response to comments on #3.		
Salt River Project	Disagree	The document would be easier to follow if the two elements were kept together in the same requirement (similar to comments stated in Comment #4 above). It makes the standard longer than necessary and creates redundancy. Also, under the new wording in R1, the Transmission Vegetation Management Program no longer has a requirement to include objectives. However, there is a phrase in R1.3 to "support the objectives" and methodologies "outlined in the..program". To be consistent with R1.3, it is recommended that R1.1 be reworded to

<table>
<tr><th>Organization</th><th>Agree?</th><th>Question 6 Comment</th></tr>
<tr><td></td><td></td><td>specify the methodologies and objectives that the Transmission Owner uses to control vegetation.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comments. However, the SDT determined that the requirements to document and implement should be separate and require different levels of Violation Risk Factors and Violation Severity Levels. Thus the SDT respectfully does not adopt your suggestion to keep the two requirements together. The SDT also disagrees with returning “objectives” to R1. We do, however, agree that there is a small dichotomy since “objectives” are no longer stated in R1, while being referenced in part 1.3. Subsequently, the SDT has removed this wording from part 1.3 Further, the SDT has revised R1 to require the Transmission Owner to specifically describe how it will conduct work to comply with the Standard in lieu of requiring the Transmission Owner to only identify general objectives.</td></tr>
<tr><td>Hydro-Quebec Transenergie (HQT)</td><td>Disagree</td><td>R1.2 and R1.3 specify calendar year. The individual entities should define the 12 month period for their programs.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comments. The annual work plan may be for a calendar year or for a fiscal year.</td></tr>
<tr><td>Western Area Power Administration, Upper Great Plains Region</td><td>Agree</td><td>The description of the annual plan now appears to require a detailed plan for each line. Under FAC-003-1, Western (UGPR) identified higher priority vegetation during aerial inspection and handled those expediciously. We then addressed a percentage of the lower priority trees based upon a number of agency defined factors (vegetation priority, ground conditions, resource availability, etc). The less rigid annual plan allowed us the freedom to cut the lower priority trees that made the best sense to cut. We are concerned that the additional rigidity will create a ever-changing annual plan because we may have to adjust dozens of lines based on inspections. We question whether it is prudent to occupy finite resources in continually modifying the annual plan when the real benefits accrue from actually performing the vegetation management activities.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comments. The SDT intent is for the Transmission Owner’s Transmission Vegetation Management Program to be developed based on the unique requirements of each Transmission Owner’s system. For example, where the Transmission Owner has a heavily forested or geographically large territory the annual plan may address many transmission lines on a cyclic basis along with additional items found on the vegetation inspections. On the other hand, where the Transmission Owner has a very sparsely forested territory, or a small number of transmission line miles, the Transmission Vegetation Management Program may necessitate an annual plan that only addresses items found on the vegetation inspections. Therefore, the specificity of the annual plan is subject to the discretion of the Transmission Owner. We agree that only the appropriate amount of resources should be applied to the execution and management of the annual plan, provided the overall Transmission Vegetation Management Program is effective.</td></tr>
<tr><td>Progress Energy Florida</td><td>Agree</td><td>Annual Plan should be a defined term in the standard. Without a definition, the term may be interpreted differently by industry and the regulator. The drafting team should raise the prominence of annual plan and define the attributes of an annual plan.</td></tr>
</table>

Organization	Agree?	Question 6 Comment
Response: The SDT thanks you for your comments. The SDT did attempt to address this concern by breaking the annual plan into 4 separate sub-requirements. We feel this may help limit the range of subjective interpretations of this requirement.		
Progress Energy Carolinas	Agree	Annual Plan should be a defined term in the standard. Without a definition, the term may be interpreted differently by industry and the regulator. The drafting team should raise the prominence of annual plan and define the attributes of an annual plan.
Response: The SDT thanks you for your comments. The SDT did attempt to address this concern by breaking the annual plan into 4 separate sub-requirements. We feel this may help limit the range of subjective interpretations of this requirement.		
Southern California Edison Company	Agree	Q6: SCE agrees in part. Proposal R1.3, requiring Transmission Owners to establish an annual maintenance plan is generally acceptable. However, SCE disagrees with including peripheral information in R1.3 and the institution of a separate implementation requirement (R9). Further, we note that some portions of FAC-003-1 (R2) appear to have been transplanted into proposed R1.3 and that the word “shall” has been replaced with the word “should”. SCE believes that inserting the word “shall” into statements that are clearly advisory in nature does not necessarily create enforceable requirements. As proposed, an enforcement auditor might incorrectly determine that the new “requirement” statements in proposed R1.3, describing the need for “flexibility”, “consideration of permitting and scheduling requirements”, and self-determined “methodologies” is a comprehensive list of items for the maintenance plan. Because this list of program elements is not complete, SCE recommends all text following the opening sentence be removed from R1.3 and inserted into the supporting technical paper. SCE respectfully suggests that R1.3 be revised to read: "Specifies a plan that identifies the applicable lines to be maintained and associated work to be performed."
Response: The SDT thanks you for your comments. The consensus of the SDT is the components of an annual work plan must be part of the requirement to ensure that all plans are adequate. Major changes that could affect reliability must be made.		
FirstEnergy	Agree	Although we agree with R1.3, we suggest it be broken up into subrequirements to allow for better clarity to the reader as well as aid in the development of violation severity levels when developed. We suggest the following:R1.3. Require an annual plan that includes the following as a minimum: (Note: Adjustments to the plan within the year are permissible) R1.3.1. It shall identify the applicable lines to be maintained and associated work to be performed during the year. R1.3.2. Is shall be flexible to adjust to changing conditions and to findings from vegetation inspections. R1.3.3. It shall take into consideration permitting and scheduling requirements from landowners or regulatory authorities. R1.3.4. It shall support the objectives of the transmission vegetation management program and use the methodologies outlined in the transmission vegetation management program.

Organization	Agree?	Question 6 Comment
Response: The SDT thanks you for your comments. Requirement R1.3 has been subdivided for clarity in proposed version 2.		
MRO NERC Standards Review Subcommittee	Agree	The MRO suggests removing the words "during the year" from sentence 1 and removing the words "within the year" in sentence 3. The MRO believes that having it only within the plan year is too restrictive.
Response: The SDT thanks you for your comments. By definition an annual plan covers a one year period. This one year period, at the discretion of the Transmission Owner, may or may not be constrained to a calendar year. However, in an effort to make the requirement more concise, the SDT did remove the words “during the year” from the requirement but retained the words “within the year” in the requirement.		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 6 and proposes that the Annual Plan be a defined term.
Response: The SDT thanks you for your comments. The SDT did attempt to address this concern by breaking the annual plan into 4 separate sub-requirements. We feel this may help limit the range of subjective interpretations of this requirement.		
American Electric Power (AEP)	Agree	AEP agrees with these changes.
Response: The SDT thanks you for your comments.		
Platte River Power Authority	Agree	Under the new working in R1., the Transmission Vegetation Management Program no longer has a requirement to include objectives. However, there is a phrase in R1.3. to "support the objectives.. and methodologies outlined in the Transmission Vegetation Management Program". R1.3. should be consistent with the wording in R1.
Response: The SDT thanks you for your comments. The SDT has made changes to address this concern and the word, “objectives” is no longer used in the revised standard.		
American Transmission Company	Agree	ATC agrees with separating the implementation Requirements from the Annual Plan Requirements.
Response: The SDT thanks you for your comments.		
Manitoba Hydro	Agree	Agree with the separation - but suggest that the time horizon of one year be removed as some changes may push the work beyond the current planning year.
Response: The SDT thanks you for your comments. By definition an annual plan covers a one year period. This one year period, at the discretion of		

Organization	Agree?	Question 6 Comment
the Transmission Owner, may or may not be constrained to a calendar year. If findings during the year from Vegetation Inspections justify changes to the plan, such adjustments are allowed as long as they occur within the planning year, not after the fact.		
San Diego Gas & Electric	Agree	To be consistent with R1.3, we recommend that R1.1 be reworded to specify the methodologies and objectives that the Transmission Owner uses to control vegetation.
Response: The SDT thanks you for your comments. The SDT has made changes to address this concern.		
CenterPoint Energy	Agree	See comments to Q4 above as well.
Response: The SDT thanks you for your comments. See response to comments on Q4.		
Great River Energy	Agree	GRE suggests removing the words "during the year" from sentence 1 and removing the words "within the year" in sentence 3. GRE believes that having it only within the plan year is too restrictive.
Response: The SDT thanks you for your comments. By definition an annual plan covers a one year period. This one year period, at the discretion of the Transmission Owner, may or may not be constrained to a calendar year. However, in an effort to make the requirement more concise, the SDT did remove the words "during the year" from the requirement but retained the words "within the year" in the requirement.		
WECC Reliability Coordination	Agree	
Associated Electric Cooperative Inc.	Agree	
SERC Vegetation Management Subcommittee (VMS)	Agree	
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
SERC OC Standards Review	Agree	

Organization	Agree?	Question 6 Comment
Group		
Florida Power & Light	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
Bonneville Power Administration	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	
Exelon	Agree	
Central Maine Power Company	Agree	
Northern California Power Agency (NCPA)	Agree	
Tampa Electric Company	Agree	
Orange and Rockland Utilities Inc.	Agree	
Ameren	Agree	

Organization	Agree?	Question 6 Comment
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Consumers Energy Company	Agree	
National Grid	Agree	
Pacific Gas & Electric Co.	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Duke Energy Corporation	Agree	
Entergy Services	Agree	
Pepco Holdings, Inc	Agree	
Northeast Utilities	Agree	
Buckeye Power, Inc.	Agree	

7. In R1.4 the Standard requires the Transmission Owner to have an Imminent Threat Procedure and specifies elements to be in that procedure. Do you agree with R1.4? If not, please explain.

Summary Consideration: Approximately half of the comments received were critical of the lack of a definition for imminent threat. The SDT prefers to allow the verbiage "an imminent threat of a vegetation-related Sustained Outage" to stand without further definition.

About the same number of commenters objected to the "prescriptive" list of other actions for the Transmission Operator, and that language has been removed from R1.4.

R1.4 Require a process or procedure for response to imminent threats of a vegetation related Sustained Outage. The process or procedure shall specify actions which shall include immediate communication of the threat to the responsible control center.

Deleted: Transmission Operator

Deleted: , and may include actions such as a temporary reduction in line Rating, switching lines out of service, or other actions.

Commenters also expressed a desire to set the procedure for specific internal needs and the SDT modified the language to give that latitude to the Transmission Owner when developing its Imminent Threat procedure.

Some comments referred to parts of the standard not asked about in this question and the SDT directed the commenters to review the changes in R1, R2 and R4.

Organization	Agree?	Question 7 Comment
Associated Electric Cooperative Inc.	Disagree	The language in R1.4, requiring notification of the Transmission Operator, is inconsistent with the Applicability in Section A.4.1.1 which designates the Transmission Owner as the responsible entity.
Response: Thank you for your comment. The main purpose of requirement R1.4 is to enhance the responsible operator's situational awareness of the power system's status. Therefore, the salient requirement of this procedure is notification of the responsible operator of any potential threat to the power system. This requirement does not mandate any action of the responsible operator and thus, this entity would not need to be listed in the Applicability section. Please also note that the wording in R1.4 has been altered to change the "Transmission Operator" to the "responsible control center", to better identify the appropriate responsible party.		
NPCC	Disagree	While we strongly agree that an imminent threat procedure should be required in the Transmission Vegetation Management Program, we disagree with some specific wording in R1.4. R1.4 requires immediate communication of an imminent threat to the Transmission Operator, which we would normally agree with. R2 however requires that the imminent threat procedure be implemented when the Critical Clearance Zone (Critical Clearance Zone) is approached by vegetation. "Approached" is not defined as a specific distance, so this part of the requirement is left up to the individual's interpretation. In cases where the Critical Clearance Zone is

Organization	Agree?	Question 7 Comment
		approached by vegetation no threat to the system is possible if the vegetation is removed before it actually grows into the Critical Clearance Zone . In many cases the vegetation can be removed without taking clearance outages because the Critical Clearance Zone is large, and the conductor and vegetation are still relatively far apart. In such cases there is no need to notify the Transmission Operator, although there is a need to remove the vegetation immediately. We recognize that the opposite is also true, and that in some cases it will be necessary to notify the Transmission Operator because a clearance outage or line de-rating may be required to remove the vegetation. We therefore suggest a simple change to the wording of the second sentence of R1.4. Change "?. specify actions which shall include immediate communication of the threat to the Transmission Operator, and may include actions such as a temporary reduction in line Rating, switching lines out of service, or other actions" to ".. specify actions which may include immediate communication of the threat to the Transmission Operator, a temporary reduction in line Rating, switching lines out of service, or other actions". This change will address the issue which is described above and will allow each Transmission Operator to develop an imminent threat procedure that best fits their system. It should also be noted that many Transmission Operators have imminent threat procedures in place to address all imminent threats to their transmission system, not just threats due to vegetation. It makes sense for Transmission Owners to have only one imminent threat process, therefore the flexibility that can be achieved in the context of this standard would be helpful.
Response: Thank you for your comment. We agree with your comments concerning the Critical Clearance Zone and the elusiveness of the term "approach". Subsequently, the Critical Clearance Zone methodology has been removed from the Standard. The SDT also agrees that the main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of the power system's status. Please also note that the wording has been altered to change the "Transmission Operator" to the "responsible control center" to better identify the appropriate responsible party. The SDT maintains that the salient requirement of this procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system.		
SERC Vegetation Management Subcommittee (VMS)	Disagree	The Requirement as written is too prescriptive and is open to interpretation, from an audit perspective, with use of the term "immediate" communication and a partial list of activities. Many conditions or threats, requiring immediate removal, would not require communication with the Transmission Operator, who is not an applicable entity for this standard. The SERC VMS recommends that R1.4 be deleted. Since this is a "zero tolerance" standard any Transmission Owner will remove any discovered threats to prevent outages. If R1.4 is not deleted, the SERC VMS believes that imminent threats should be a defined term. The definition should be as follows: ?Imminent Threat: A vegetation condition which, if not addressed, will place a transmission line at a significant risk of a Sustained Outage.?
Response: Thank you for your comment. We agree that an imminent threat can exist in many different forms. Part of your concern has been addressed by the removal of the term "immediate". However, the SDT does not agree with removing the imminent threat requirement. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to		

Organization	Agree?	Question 7 Comment
better identify the appropriate party. The salient requirement of the imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system.		
Progress Energy Florida	Disagree	Progress Energy agrees with the need for a Transmission Owner to have an Imminent Threat Procedure and that the Transmission Operator should be immediately notified of imminent threats but only when it is appropriate as defined by the Transmission Owner's imminent threat procedure. We disagree with the requirement to immediately communicate with the Transmission Operator whenever the Critical Clearance Zone is approached. Not every scenario is an issue that requires action by the Transmission Operator: It is possible that the Critical Clearance Zone is being approached by vegetation at the lowest point of the Critical Clearance Zone whereas the conductor may be at its highest point in the Critical Clearance Zone (potentially 30 feet away from the vegetation) -- This typical situation does not merit notification to the Transmission Operator (which is required by FAC-003-2 as currently written).
Response: Thank you for your comment. We agree with your comments concerning the Critical Clearance Zone methodology. Subsequently, the Critical Clearance Zone methodology has been removed from the Standard. The SDT also agrees that the main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please also note that the requirement wording has been altered to change the "Transmission Operator" to the "responsible control center". The SDT feels this better identifies the appropriate party. The SDT maintains that the salient requirement of R1.4 is notifying the responsible operator of any imminent threat to the power system.		
Progress Energy Carolinas	Disagree	Progress Energy agrees with the need for a Transmission Owner to have an Imminent Threat Procedure and that the Transmission Operator should be immediately notified of imminent threats but only when it is appropriate as defined by the Transmission Owner's imminent threat procedure. We disagree with the requirement to immediately communicate with the Transmission Operator whenever the Critical Clearance Zone is approached. Not every scenario is an issue that requires action by the Transmission Operator: It is possible that the Critical Clearance Zone is being approached by vegetation at the lowest point of the Critical Clearance Zone whereas the conductor may be at its highest point in the Critical Clearance Zone (potentially 30 feet away from the vegetation) -- This typical situation does not merit notification to the Transmission Operator (which is required by FAC-003-2 as currently written).
Response: Thank you for your comment. We agree with your comments concerning the Critical Clearance Zone methodology. Subsequently, the Critical Clearance Zone methodology has been removed from the Standard. The SDT also agrees that the main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please also note that the requirement wording has been altered to change the "Transmission Operator" to the "responsible control center". The SDT feels this better identifies the appropriate party. The SDT maintains that the salient requirement of R1.4 is notifying the responsible operator of any imminent threat to the power		

Organization	Agree?	Question 7 Comment
system.		
SERC OC Standards Review Group	Disagree	The Requirement as written is too prescriptive and is open to interpretation from an audit perspective with use of the term “immediate” communication and a partial list of activities. Due to limitations of communication capabilities in the field, "immediate" may not be practical. While the White Paper provides insight into what is acceptable communications to the Transmission Operator, the standard is less prescriptive in describing what is an acceptable communication path to the Transmission Operator. We recommend better descriptions in VSLs, measures and the Reliability Standard Audit Worksheet as to what is acceptable. Many conditions or threats, requiring immediate removal, would not require communication with the Transmission Operator, who is not an applicable entity for this standard. The SERC OCSRG recommends that R1.4 be deleted. Since this is a "zero tolerance" standard any Transmission Owner will remove any discovered threats to prevent outages. If R1.4 is not deleted, the SERC OCSRG believes that imminent threats should be a defined term. The definition should be as follows: “Imminent Threat: A vegetation condition which, if not addressed, will place a transmission line at an immediate risk of a Sustained Outage.”
Response: Thank you for your comment. Part of your concern has been addressed by the removal of the term “immediate”. However, the SDT does not agree with removing the imminent threat requirement. The main purpose of the imminent threat requirement is to enhance the responsible control center’s situational awareness of reliability dangers to the power system. Please note that this requirement’s wording has also been altered to change the designation “Transmission Operator” to the “responsible control center” to better identify the appropriate party. The salient requirement of the imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system and field communication capabilities. The SDT also feels that it is important for the aspects of the imminent threat procedure and the triggers be defined by the Transmission Owner. The Violation Severity Levels for this requirement are now binary and self explanatory. The SDT is prepared to provide input in the revision of RSAWs, but under current practice, RSAWs are not developed by standard drafting teams.		
Florida Power & Light	Disagree	The definition of Imminent Threat procedure should be included in the Standard. As FERC has stated with regard to the definition of sabotage, the industry should come up with a standard definition and it should not vary from company-to-company. FPL further disagrees with defining Imminent Threat only in a white paper as proposed by some. The Standard should not refer to other reference documents, especially when it is to add clarity and should define the Imminent Threat procedure as well as its requirements within the body of the Standard.
Response: Thank you for your comment. The SDT disagrees with your comments. We feel that the Transmission Owner should have the flexibility to not only develop the imminent threat procedure but also define the triggers needed for its particular system. The main purpose of the imminent threat requirement is to enhance the responsible control center’s situational awareness of reliability dangers to the power system. The notification requirement is a mandatory requirement for all Transmission Owners. Please note that this requirement’s wording has also been altered to change the designation “Transmission Operator” to the “responsible control center” to better identify the appropriate party. Beyond this, it is left to the		

Organization	Agree?	Question 7 Comment
Transmission Owner to develop all other imminent threat procedure components.		
Southern Company	Disagree	The standard requirement, as written, requires the "immediate notification" of the operator. This standard requirement could be interpreted to mandate that this notification take place prior to any other action. There could be times that this communication would take up valuable time needed to relieve the immediate threat. The requirement should be modified to list examples of appropriate actions that could be taken. The Transmisison Owner should be allowed the flexibility of developing a communication process that ensures timely notification of a threat and the proper channels of communication that will be utilized in making the notification. The present wording in the standard alone suggests the individual observing the threat in the field is directly responsible for communicating with the Transmission Operator while the whitepaper tends to be more flexible. The Transmission Owner may wish to have the vegetation contractor notify the Transmisison Owner's forester who in turn will notify the Transmission Operator. While the whitepaper does an adequate job describing acceptable responses, the standard does not. It is recommend the standard, VSL, and Reliability Standard Audit Worksheet better explain what is an acceptable response to the Transmission OwnerP. The requirement then goes on to address specific actions the operator "may" take in response to the notification. The imminent threat processes should be limited to the steps taken to notify the Transmission Operator in a timely manner. FAC-003 is not the appropriate place to address Transmission Operator decisions resulting from notification of a threat to the system.
Response: Thank you for your comment. Part of your concern has been addressed by the removal of the term “immediate”. We agree that the main purpose of this requirement is to enhance the responsible control center’s situational awareness of reliability dangers to the power system. Further, please note that the requirement wording has also been altered to change the designation “Transmission Operator” to the “responsible control center” to better identify the appropriate party. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system and field communication capabilities. The Violation Severity Levels for this requirement are now binary and self explanatory. The SDT is prepared to provide input in the revision of RSAWs, but under current practice, RSAWs are not developed by standard drafting teams.		
E.ON U.S.	Disagree	The Requirement as written is too prescriptive and is open to interpretation, from an audit perspective, with use of the term “immediate” communication and a partial list of activities. Many conditions or threats, requiring immediate removal, would not require communication with the Transmission Operator, who is not an applicable entity for this standard. We suggest that R1.4 be deleted. Since this is a "zero tolerance" standard any Transmission Owner will remove any discovered threats to prevent outages. If R1.4 is not deleted, we believe that imminent threats should be a defined term. The definition should be as follows: “Imminent Threat: A vegetation condition which, if not addressed, will place a transmission line at a significant risk of a Sustained Outage.”
Response: Thank you for your comment. We agree that an imminent threat can exist in many different forms. Part of your concern has been addressed by the removal of the term “immediate”. However, the SDT does not agree with removing the imminent threat requirement. The main		

Organization	Agree?	Question 7 Comment
purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of this procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system.		
Midwest ISO Stakeholders Standards Collaborators	Disagree	Transmission Owners should have a Vegetation Imminent Threat Procedure, and "Vegetation Imminent Threat" should be a defined term, defined as: "Vegetation observed in the field encroaching upon a conductor within a distance that is twice the Gallet clearance distances referenced in Table I of the draft standard FAC-003-2." In this case, the threat would require an immediate response and would include communication to the Transmission Operator. From there, the actions that the operator decides to take will be dependent on the incident and system conditions. We do not need to be prescriptive with this requirement but rather allow the Transmission Operator and appropriate field personnel the flexibility to make the right decisions to safely, promptly and appropriately remove the vegetation threat. From a Transmission Owner's perspective, many situations can constitute an imminent threat but this approach will clearly define a "Vegetation Imminent Threat" as it relates to the Purpose of this standard. See our related comment on #11 below.
Response: Thank you for your comment. We agree that many situations can constitute an imminent threat. While we do not agree that an imminent threat should be defined in the Standard, we do agree that the Transmission Owner should have the flexibility to develop an imminent threat procedure that allows the appropriate decisions to address the vegetation threat. This requirement allows the Transmission Owner to develop an imminent threat procedure that best fits its system. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The SDT feels this is a better approach than to have a rigid definition of an imminent threat procedure.		
SERC Compliance Staff	Disagree	SERC staff agrees with the concept of an imminent threat procedure, but disagrees with this requirement in its current form. The use of the word "immediate" is ambiguous. There are many conditions or threats that may require immediate removal, but would not require communication with the Transmission Operator and may require communication with another entity. SERC staff suggests that the proper communication paths be outlined by the Transmission Owner. Imminent threats should be a defined term, however SERC staff has not developed an objective, unambiguous definition.
Response: Thank you for your comment. Part of your concern has been addressed by the removal of the term "immediate". We agree that the main purpose of the imminent threat requirement is the timely communication of a threat to the responsible operator. Therefore, the requirement wording has been altered to change the designation "Transmission Operator" to the "responsible control center". The main purpose of this requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. While we do agree that the Transmission Owner should outline the proper communication paths, we do not agree that an imminent threat should be defined in the Standard. The SDT feels the		

Organization	Agree?	Question 7 Comment
Transmission Owner should have the flexibility to develop an imminent threat procedure that best fits its system.		
ITC HOLDINGS	Disagree	Agree & Disagree with the question: Agree with the need to have an Imminent Threat Procedure and upon discovery of an IT, the Transmission Operations (Transmission Owner) should be notified. We Disagree however, with the requirement as written as its too prescriptive and is open to interpretation, from an audit perspective, with use of the term “immediate” communication and a partial list of activities that the Transmission Owner may consider. Decisions on what specific system operating actions that could be taken are beyond the responsibility of the vegetation management personnel. Disagree with the need to implement the imminent threat procedure merely because a Critical Clearance Zone is being approached. It is possible that the Critical Clearance Zone is being approached by vegetation at the lowest point of the Critical Clearance Zone where the conductor may be at its highest point in the Critical Clearance Zone , (potentially 20 or 30 feet from vegetation) and wouldn’t necessitate notification to the Transmission Owner. Is there a desired distance from the Critical Clearance Zone where this procedure must be implemented since all vegetation within a Right-of-Way will approach the Critical Clearance Zone as it grows? R1.4 should be changed to ?Require a process for response to vegetation related imminent threat to applicable lines and not the Critical Clearance Zone
Response: Thank you for your comment. We agree with your comments concerning the Critical Clearance Zone and the elusiveness of the terms “approach” and “immediate”. Subsequently, the Critical Clearance Zone methodology has been removed from the Standard. Also, the term “immediate” has been removed. The main purpose of the imminent threat requirement is to enhance the responsible control center’s situational awareness of the power system’s status. Please also note that the wording has been altered to change the “Transmission Operator” to the “responsible control center” to better identify the appropriate responsible party. The SDT maintains that the salient requirement of the imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system.		
Tennessee Valley Authority	Disagree	TVA recommends that R1.4 and R2 both be removed from this Standard. This is a "zero tolerance" Standard with significant penalties for outage violations. These penalty conditions are the necessary and sufficient conditions for the Transmission Owner to immediately react to any discovered threats to prevent potential outages.
Response: Thank you for your comments. While the drafting team does agree that the penalties for the “zero tolerance” aspect of the Standard certainly provide a strong incentive, we still feel that a requirement for an imminent threat procedure should be included in the Standard. The main purpose of the imminent threat requirement is to enhance the responsible control center’s situational awareness of reliability dangers to the power system. Please note that this requirement’s wording has been altered to change the designation “Transmission Operator” to the “responsible control center” to better identify the appropriate party. The salient part of this procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, the Transmission Owner should develop all other components of the imminent threat procedure to best fit its system.		

Organization	Agree?	Question 7 Comment
American Electric Power (AEP)	Disagree	AEP agrees with the need for a Transmission Owner to have an Imminent Threat Procedure and that the Transmission Operator should be immediately notified of imminent threats. However, AEP disagrees with the requirement that the Transmission Operator be notified merely because the Cricitical Clearance Zone (Critical Clearance Zone) has been approached. It is possible that the Critical Clearance Zone is encroached by vegetation at the lowest point of the Critical Clearance Zone whereas the conductor may be at its highest point in the Critical Clearance Zone (potentially 20 or 30 feet away from the vegetation). This situation does not merit notification to the Transmission Operator. Please also refer to our comments regarding Critical Clearance Zone in AEP's responses to Questions 15 and 18.
Response: Thank you for your comment. We agree with your comments concerning the Critical Clearance Zone and the elusiveness of the term “approach”. Subsequently, the Critical Clearance Zone methodology has been removed from the Standard. The SDT feels that the main purpose of the imminent threat requirement is to enhance the responsible control center’s situational awareness of the power system’s status. Please also note that the wording has been altered to change the “Transmission Operator” to the “responsible control center” to better identify the appropriate responsible party. The SDT maintains that the salient requirement of this procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system.		
Tampa Electric Company	Disagree	TECO aggres with the need for the Imminent Threat Procedure. However, the use of the new Critical Clearance Zone could create a "fill in the blank" standard. We need to lock these clearances down as an industry so as to define what is an imminent threat and what the Critical Clearance Zone is in terms of specific distances.
Response: Thank you for your comments. The SDT agrees with your concern of having a standard with “fill in the blank” requirements. We have made some major changes to this requirement due to the overwhelming response from industry that the imminent threat requirement was needed but should not be overly prescriptive. The main purpose of the imminent threat requirement is to enhance the responsible control center’s situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation “Transmission Operator” to the “responsible control center” to better identify the appropriate party. The salient part of the imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. **Using the Critical Clearance Zone as an undefined “trigger” for implementing the imminent threat process has been removed from the Standard. The Critical Clearance Zone methodology has been deleted from the Standard.**		
Orange and Rockland Utilities Inc.	Disagree	While we agree that the imminent threat procedure should be included in the Transmission Vegetation Management Program, the requirement is overly prescriptive and should be revised to allow Transmission Owners flexibility to develop imminent threat procedures which best fit their systems and protocols. We recommend that R1.4 be reworded as follows: "Require a process or procedure for response to vegetation-related imminent threats to applicable lines. The imminent threat procedure shall require action to eliminate vegetation-related imminent threats, and shall be implemented upon discovery of such conditions". In addition, the definition of "Imminent Threat" should be defined. We suggest the following: "A condition which places a

Organization	Agree?	Question 7 Comment
		transmission line at significant risk of an outage in the very near term". An example of a vegetation-related imminent threat would be an uprooted tree leaning precariously toward a conductor which is certain to make contact with the conductor as the tree falls. Many Transmission Operators have imminent threat procedures in place to address all imminent threats to their transmission systems, not just imminent threats due to vegetation. In many cases it would make sense for Transmission Owners to have one imminent threat process that covers all imminent threat conditions. The flexibility being recommended would facilitate this.
Response: Thank you for your comment. The SDT agrees that the requirement was overly prescriptive. The requirement has been revised to focus on the main purpose of the imminent threat requirement; which is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient part of this procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its systems and protocols; thereby providing for the flexibility that you have suggested. Along with this line of reasoning, we do not agree that an imminent threat should be defined in the Standard. Again, the SDT feels that the Transmission Owner should have the flexibility to define what constitutes an imminent threat to its individual power system. This flexibility also allows the Transmission Owner to have one imminent threat process in place to cover all imminent threats to its transmission systems, not just imminent threats due to vegetation as you have noted.		
American Transmission Company	Disagree	We agree that entities should have a Vegetation Imminent Threat Procedure, but that the term should be defined. Also see related comments to Question #11.
Response: Thank you for your comment. We have made some major changes to this requirement due to the overwhelming response from industry that the imminent threat requirement was needed, as long as it was not an overly prescriptive requirement. We do not agree that an imminent threat should be defined in the Standard. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its system. The SDT feels this is a better approach than to have a rigid definition of an imminent threat procedure.		
Nebraska Public Power District	Disagree	NPPD agrees that a Transmission Owner should have an imminent threat procedure and the Transmission Owner be immediately notified of any threats. NPPD disagrees with prescribing what needs to be done as a result of the threat. This is condition based and staff can make the right decision as to what corrective actions are necessary.
Response: Thank you for your comment. The SDT agrees that prescribing what needs to be done as a result of the threat should not be included as part of the Standard requirement. This language has been removed from the text as you have suggested. The SDT also agrees that the main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system.		

Organization	Agree?	Question 7 Comment
Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its system.		
Consumers Energy Company	Disagree	Consumers Energy believes that each Transmission Owner/Operator should have a Vegetation Imminent Threat Procedure. We disagree with this requirement because "vegetation imminent threat" is not defined in the standard. As interpreted, the "vegetation imminent threat" is only what is needed to avoid violating the Gallet formula minimum distance which would allow vegetation approaching close to 3 feet of separation on 345 kV conductors. At this distance, removal of the tree cannot occur without removing the line from service per OSHA rules. Therefore, the tree can "cause" an outage but be acceptable under this standard. Consumers Energy believes that vegetation must be maintained so that extraordinary measures needed to remove the vegetation threat do not have to occur in order to complete the work. Thus, the minimum distance to "trigger" an imminent threat must be greater than the OSHA minimum working distance and therefore the Gallet formula does not provide the protection that FERC demands. During high load periods options a system operator may have to mitigate the vegetation threat may not be available; you may not be able to remove the line from service, derate the line, etc., so the operator must "hope" to get through the high load period without the vegetation causing a outage. Allowing vegetation to approach the Gallet formula distance is unacceptable and severely decreases the reliability of the system.
Response: Thank you for your comment. The SDT does not agree that a vegetation imminent threat should be defined in the Standard. The Critical Clearance Zone methodology has been removed from the Standard. We feel that the Transmission Owner should have the flexibility to not only develop the imminent threat procedure but also define the triggers needed for its particular system. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. The notification requirement is a mandatory requirement for all Transmission Owners. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The SDT maintains that the salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its system. Aside from the negative economic and operational impacts associated with unscheduled facility outages, failures by the Transmission Owner to effectively execute follow up activities and procedures will most likely lead to a violation(s) of other requirements related to Minimum Vegetation Clearance Distance (MVCD) encroachment or sustained outages.		
Ameren	Disagree	Transmission Owners should have a Vegetation Imminent Threat Procedure, and "Vegetation Imminent Threat" should be a defined term, defined as: "Vegetation observed in the field encroaching upon a conductor within a distance defined in the Vegetation Management plan." In this case, the threat would require an immediate response and would include communication to the Transmission Operator. From there, the actions that the operator decides to take will be dependent on the incident and system conditions. We do not need to be

Organization	Agree?	Question 7 Comment
		prescriptive with this requirement but rather allow the Transmission Operator and appropriate field personnel the flexibility to make the right decisions to safely, promptly and appropriately remove the vegetation threat. From a Transmission Owner's perspective, many situations can constitute an imminent threat but this approach will clearly define a "Vegetation Imminent Threat" as it relates to the Purpose of this standard. While a definition of "Vegetation Imminent Threat - Vegetation observed in the field encroaching upon a conductor within a distance that is twice the Gallet clearance distances referenced in Table I of the draft standard FAC-003-2" would be acceptable and far superior to that which is proposed, it will still be difficult for field personnel to identify, at each foot of a transmission circuit, wherein twice the Gallet distance would be found. See comment on #11 below.
Response: Thank you for your comment. We agree with your assessment that the Standard needs an imminent threat requirement, but as it was written, the requirement was overly prescriptive. As a result, and because much of the industry agreed with you, we have made some major changes to this requirement. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. **We further agree that many situations can constitute an imminent threat, distance from the vegetation to the conductor being only one of such situations, so the references to the Critical Clearance Zone methodology as a defined "trigger" for implementing the imminent threat process has been removed from the Standard. For that matter, the Critical Clearance Zone methodology has been deleted from the Standard. While we do not agree that an imminent threat should be defined in the Standard, we do agree that the Transmission Owner should have the flexibility to develop an imminent threat procedure that allows the appropriate decisions to address the vegetation threat. The requirement, as it has been reworded, allows the Transmission Owner to develop an imminent threat procedure that best fits its system. The SDT feels this is a better approach than to have a rigid definition of an imminent threat procedure.**		
Consolidated Edison Company of New York (CECONY)	Disagree	CECONY currently has procedures that mandate response to imminent threats. The Standard should be made more general and not identify the specific actions that shall be taken in the procedure. The second sentence of R1.4 should be deleted and the first sentence should read, 'Require a process or procedure to respond to vegetation-related imminent threats." This adds the necessary flexibility that utilities require and avoids additional redundant processes or procedures from being developed.
Response: Thank you for your comment. The SDT agrees that the requirement should be more general and has revised the requirement to focus on the main purpose of the imminent threat requirement; which is, to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its systems and protocols, thereby providing for the flexibility that you have suggested.		

Organization	Agree?	Question 7 Comment
Duke Energy Corporation	Disagree	Duke believes that Transmission Owners should have a Vegetation Imminent Threat Procedure, and "Vegetation Imminent Threat" should be a defined term, defined as: "Vegetation observed in the field encroaching upon a conductor within a distance that is twice the Gallet clearance distances referenced in Table I of the draft standard FAC-003-2." In this case, the threat would require an immediate response and would include communication to the Transmission Operator. From there, the actions that the operator decides to take will be dependent on the incident and system conditions. We do not need to be prescriptive with this requirement but rather allow the Transmission Operator and appropriate field personnel the flexibility to make the right decisions to safely, promptly and appropriately remove the vegetation threat. From a Transmission Owner's perspective, many situations can constitute an imminent threat but this approach will clearly define a "Vegetation Imminent Threat" as it relates to the Purpose of this standard. See our related comment on #11 below.
Response: Thank you for your comment. While we do not agree that an imminent threat should be defined in the Standard, we do agree with your assessment that the Standard needs an imminent threat requirement, but as it was written, the requirement was overly prescriptive. As a result, and because much of the industry agreed with you, we have made some major changes to this requirement. The Critical Clearance Zone methodology has been deleted from the Standard. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any potential threat to the power system. Beyond this, it is left to the Transmission Owner to determine the "triggers", follow up activities, and procedures that best fit its system; thereby providing for the flexibility that you have suggested. The SDT feels this is a better approach than to have a rigid definition of an imminent threat procedure.		
Entergy Services	Disagree	1. The requirement should state that each Transmission Owner will be responsible for creating and maintaining a Vegetation Imminent Threat Process. This process will clearly define how the Transmission Owner defines a vegetation imminent threat. 2. The requirement needs to state that only vegetation conditions identified, to the Transmission Owner, by regular field inspections, including aerial inspections, and other internal and external verifiable reports of vegetation imminent threats will be managed through this process. 3. If the standard requires a process to mitigate potential immediate threats to the system, the term ?vegetation imminent threat? must be defined. This definition must not delineate the precise steps that are required to be taken to allow experts as many options as necessary to address each vegetation condition specifically. 4. The list of possible mitigating actions should be removed from the standard since it is not an all inclusive list. Listing these actions in the standard may imply that the entity must do one or all of the actions to be in compliance. The entity must have sufficient latitude to evaluate each possible vegetation condition and apply the most appropriate mitigation steps, up to and including the removal of the identified vegetation.

Organization	Agree?	Question 7 Comment
Response: Thank you for your comments. **1. The SDT prefers to allow the verbiage "an imminent threat of a vegetation-related Sustained Outage" to stand without further definition. The SDT agrees that the Standard needs an imminent threat requirement. However, as it was written for the initial posting, the requirement was overly prescriptive. As a result, and because much of the industry agreed with you, the SDT has made some changes to this requirement. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to permit communication with the relevant entity for the Transmission Owner. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the "triggers", follow up activities, and procedures that best fit its system, thereby providing for the flexibility that you have suggested. The SDT feels this is a better approach than to have a rigid definition of an imminent threat procedure.** **2. See response 1 above.** **3. See response 1 above.** **4. See response 1 above.**		
Salt River Project	Disagree	Agree with R1.4, however with the suggested change: Remove the language "?and may include actions such as a temporary reduction in line Rating, switching lines out of service, or other actions.". Any standard should not contain advisory-type language, it should be declarative in tone. The suggested actions are not the responsibility of the vegetation management program.
Response: Thank you for your comment. The advisory type language has been removed from the requirement as you have suggested. The SDT also agrees that these "advisory" actions could fall outside the responsibility of some utilities' Transmission Vegetation Management Program. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation.		
Northeast Utilities	Disagree	Agree with the need to have and implement when necessary an imminent threat procedure. Disagree with the need to implement the imminent threat procedure merely because a Critical Clearance Zone is being approached, as required by R2. Is there a desired distance from the Critical Clearance Zone where this procedure must be implemented, since all vegetation within a right-of-way will "approach" the Critical Clearance Zone as it grows? How will time of year and operating conditions be factored in, which may change the requirements to perform control during periods of low temperature or low load? It would not be necessary to perform all the requirements of an imminent threat procedure when there is adequate clearance to schedule the

Organization	Agree?	Question 7 Comment
		work without jeopardizing the reliability of the system. For example, in mid winter a line is 8 feet from a tree - there is little chance of the line reacing maximum sag at that time of year and the present condition does not constitute an imminent threat at that time. Also, disagree with the requirement for the imminent threat procedure to include actions that could be taken by the Transmission OwnerP (reduction in line rating, switching). The requirement should be limited to notifications to the Transmission OwnerP, since decisions on what specific system operating actions to take are beyond the responsibility of the Transmission Owner. The decision on what actions to take needs to be performed either by the Transmission OwnerP, or by the Transmission OwnerP in conjunction with the Transmission Owner.
Response: Thank you for your comments. We agree with your comments concerning the Critical Clearance Zone and the elusiveness of the term "approach". Subsequently, the Critical Clearance Zone methodology as it refers to the imminent threat process has been removed from the Standard. The SDT also agrees that the main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of the power system's status. . Please also note that the wording has been altered to change the "Transmission Operator" to the "responsible control center" to better identify the appropriate responsible party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system, and allows the Transmission Owner to make appropriate decisions on follow up actions.		
Hydro-Quebec Transenergie (HQT)	Disagree	While we strongly agree that an imminent threat procedure should be required in the Transmission Vegetation Management Program, we disagree with some specific wording in R1.4. R1.4 requires immediate communication of an imminent threat to the Transmission Operator, which we would normally agree with. R2 however requires that the imminent threat procedure be implemented when the Critical Clearance Zone (Critical Clearance Zone) is approached by vegetation. "Approached" is not defined as a specific distance, so this part of the requirement is left up to the individual's interpretation. In cases where the Critical Clearance Zone is approached by vegetation no threat to the system is possible if the vegetation is removed before it actually grows into the Critical Clearance Zone . In many cases the vegetation can be removed without taking clearance outages because the Critical Clearance Zone is large, and the conductor and vegetation are still relatively far apart. In such cases there is no need to notify the Transmission Operator, although there is a need to remove the vegetation immediately. We recognize that the opposite is also true, and that in some cases it will be necessary to notify the Transmission Operator because a clearance outage or line de-rating may be required to remove the vegetation. We therefore suggest a simple change to the wording of the second sentence of R1.4. Change "?. specify actions which shall include immediate communication of the threat to the Transmission Operator, and may include actions such as a temporary reduction in line Rating, switching lines out of service, or other actions" to ".. specify actions which may include immediate communication of the threat to the Transmission Operator, a temporary reduction in line Rating, switching lines out of service, or other actions". This change will address the issue which is described above and will allow each Transmission Operator to develop an imminent threat procedure that best fits their system. It should also be noted that many Transmission Operators have imminent threat procedures in place to address all imminent threats to their transmission system,

Organization	Agree?	Question 7 Comment
		not just threats due to vegetation. It makes sense for Transmission Owners to have only one imminent threat process; therefore the flexibility that can be achieved in the context of this standard would be helpful.
Response: Thank you for your comments. We agree with your comments concerning the Critical Clearance Zone and the elusiveness of the term "approach". Subsequently, the Critical Clearance Zone methodology has been removed from the Standard. The SDT feels that the main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of the power system's status. The wording about other follow up actions that could be taken has been removed from the requirement. Please also note that the wording has been altered to change the "Transmission Operator" to the "responsible control center" to better identify the appropriate responsible party. The SDT maintains that the salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system.		
Pepco Holdings, Inc	Disagree	While an imminent threat procedure is prudent and reasonable, it does not need to consider a Critical Clearance Zone as addressed in our comments on other questions. In fact, one can quickly provide examples of imminent threats when the threat is not even on the right of way. The Transmission Owner should simply have an imminent threat procedure to address identified imminent or potential imminent threats.
Response: Thank you for your comment. We agree with your comments concerning the Critical Clearance Zone methodology. Subsequently, the Critical Clearance Zone methodology has been removed from the Standard. The SDT feels that the main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of the power system's status. Please also note that the requirement wording has been altered to change the "Transmission Operator" to the "responsible control center" to better identify the appropriate responsible party. The SDT maintains that the salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, the SDT agrees that it should be left to the Transmission Owner to develop an imminent threat procedure that best fits its system.		
Southern California Edison Company	Agree	Q7: SCE agrees in part with the content of R1.4 because of its similarity to existing requirement R1.5 in FAC-003-1. However, we disagree with the drafter's inclusion of peripheral information following the first sentence. We also note that the second sentence of proposed R1.4 includes both a requirement and a recommendation. SCE believes this and similar recommendations are best suited for the supporting technical paper. SCE respectfully suggests that R1.4 be revised to read: "Specify a process or procedure for communicating an impending vegetation-to-line contact that may result in a sustained outage and the appropriate response measures."
Response: Thank you for your comment. The SDT feels that the main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of the power system's status. We agree with your suggestions to exclude some of the peripheral language included in this requirement. Thus, the SDT has removed references to the Critical Clearance Zone, the word "immediate", and the wording referring to other actions that may be taken by the responsible operator. Please also note that the wording has been altered to change the "Transmission		

Organization	Agree?	Question 7 Comment
Operator" to the "responsible control center" to better identify the appropriate responsible party.		
Western Utility Arborists	Agree	We agree with 1.4, with the following qualification: Any standard that is developed should not contain advisory-type language" it should be declarative in tone. For example, in R1.4, the ending clause that begins "and may include actions" should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program.
Response: Thank you for your comments. The advisory type language has been removed from the requirement as you have suggested. The SDT also agrees that these "advisory" actions could fall outside the responsibility of some utilities' Transmission Vegetation Management Program. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation.		
Bonneville Power Administration	Agree	BPA agrees with 1.4, with the following change. The ending phrase: "and may include actions such as a temporary reduction in line Rating, switching lines out of service, or other actions" should be eliminated. Not only does BPA feel it is inappropriate to use advisory-type rather than declarative language in a Standard, BPA feels it is also questionable to give examples of imminent response actions that are often not within the direct capability of a vegetation program to enact. Eliminating the reference to these possible actions leaves it up to the Transmission Operator to decide what the eminent threat response is.
Response: Thank you for your comment. The advisory type language has been removed from the requirement as you have suggested. The SDT also agrees that these "advisory" actions could fall outside the direct capability of some utilities' Transmission Vegetation Management Program. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation.		
FirstEnergy	Agree	The safety of the personnel required to remove a tree or vegetation on or near an energized conductor must be considered when implementing the imminent threat procedure. Although this is a reliability standard, the safety of the personnel may be one "trigger" to implement the imminent threat procedure. That being said, the workers on site, in their judgment, are not able to remove the vegetation safely then the imminent threat procedure would be implemented. See comments for Critical Clearance Zone .
Response: Thank you for your comment. The SDT also believes human safety must be major consideration in this requirement. The Transmission		

Organization	Agree?	Question 7 Comment
Owner may include in its Imminent Threat procedure appropriate considerations for personnel safety as a trigger. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. The SDT made major changes to make the requirement less prescriptive. Also, the wording has been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation. The Critical Clearance Zone methodology has been removed from the Standard.		
MRO NERC Standards Review Subcommittee	Agree	The MRO agrees and believes that it is very important for the applicable entities to posses a Imminent Threat Procedure. The MRO also believes that the term "Imminent Threat" is subjective an should be defined.
Response: Thank you for your comment. We have made some major changes to this requirement due to the overwhelming response from industry that the imminent threat requirement was needed, as long as it was not an overly prescriptive requirement. We do not agree that an imminent threat should be defined in the Standard. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its system. The SDT feels this is a better approach than to have a rigid definition of an imminent threat procedure.		
Western Area Power Administration, Rocky Mountain Region	Agree	The Technical Reference document could be expanded to explain that a well rounded Imminent Threat Procedure should contain many mitigation alternatives to appropriately address a wide range of field situations, including a "no immediate field action is required" option. For example, further investigation of a potential imminent threat situation may reveal that the situation has been erroneously reported or incorrectly measured and therefore no immediate vegetation removal actions are required. A utility's Imminent Threat Procedure may also address situations beyond just vegetation related incidents.
Response: Thank you for your comment. The SDT agrees that many situations can constitute an imminent threat beyond just vegetation related incidents. The requirement has been rewritten to focus on the main purpose of the imminent threat requirement; which is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any potential threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit the wide range of field situations that are possible to encounter.		
Platte River Power Authority	Agree	Imminent threat is not a defined term in the NERC Glossary of Terms so it could be construed as a fill-in-the-blank requirement by FERC as each Transmission Owner could define Imminent Threat differently. Imminent threat should be defined or the requirement should be reworded to define what types of situations would require a procedure. Also, the language, "and may include actions such as a temporary reduction in line rating, switching

Organization	Agree?	Question 7 Comment
		lines out of service, or other actions" should be removed from the standard but could be included in the imminent threat procedure or definition.
Response: The SDT has made some major changes to this requirement due to the overwhelming response from industry that the imminent threat requirement was needed, as long as it was not an overly prescriptive requirement. For instance, we agree that the wording referring to other follow up actions that may be taken by the operator is too prescriptive and has been removed from this requirement. **The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The SDT feels this is a better approach than to have a rigid definition of an imminent threat procedure. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit the wide range of field situations that are possible to encounter.**		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	The USFS would be expecting the Transmission Owner to be documenting the imminent threat procedures in an operating plan or corridor management plan that would be approved by the designated USFS decision maker. If such procedures are documented in the Transmission Owner's Transmission Vegetation Management Program and are compatible with USFS resource management direction, then the imminent threat procedures could be incorporated in the agency-approved operating plan by reference. If the Transmission Owner disputes any restrictions that are placed by the USFS on the imminent threat procedures, the USFS has an administrative appeals process which the Transmission Owner can use, but those procedures can be time-consuming and probably would not be perceived by the Transmission Owner as being neutral for negotiation purposes. It might help if a third federal party like NERC could help resolve disputes between the Transmission Owner and the USFS on the imminent threat procedures. Although the USFS would object to unreasonable intrusion of NERC into normal USFS land management prerogatives, imminent threat procedures would seem to be a topic for which NERC should take a very strong position, especially with a standard that identifies minimum vegetation clearances as related to prevention of arcing potential, or in other words, vegetation that should be considered hazardous and in immediate need of treatment.
Response: Thank you for your comments. The SDT developed this standard to apply to Transmission Owners in support of bulk electric system reliability. While there may be similar areas of regulation between the purview of NERC and the USFS, this standard is not intended to be incompatible with any USFS resource management direction. That being said, any NERC standard approved by the FERC does not need to be incorporated into "the agency-approved operating plan". In regard to the suggestion that NERC assist in resolving disputes between USFS and Transmission Owners, this would be beyond the scope of NERC. **The SDT suggests that USFS and affected Transmission Owners review language in permits and change that language to allow perpetual ingress and egress and vegetation maintenance without case-by-case application and review. Such a change would prevent current problems where it takes**		

Organization	Agree?	Question 7 Comment
upwards of one year before vegetation maintenance is allowed to proceed. **The SDT has made some major changes to this requirement due to the overwhelming response from industry that the imminent threat requirement was needed, as long as it was not an overly prescriptive requirement. For instance, we agree that the wording referring to other follow up actions that may be taken by the operator is too prescriptive and has been removed from this requirement.** **The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The SDT feels this is a better approach than to have a rigid definition of an imminent threat procedure. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit the wide range of field situations that are possible to encounter.**		
Manitoba Hydro	Agree	Suggest removing, "and may include actions such as a temporary reduction in line rating, switching lines out of service, or other actions", as this is outside the scope of a vegetation management program.
Response: Thank you for your comment. The language you mention has been removed from the requirement as you have suggested. The SDT agrees that these actions could fall outside the scope of some utilities' Transmission Vegetation Management Program. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation.		
Pacific Gas & Electric Co.	Agree	PG&E agrees an imminent threat procedure is a critical component of the standard and should be contained in the Transmission Vegetation Management Program. See additional comments for Q11.
Response: Thank you for your comment. See the responses to comments on Q11.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	We agree with 1.4, with the following qualification: Any standard that is developed should not contain advisory-type language? it should be declarative in tone. For example, in R1.4, the ending clause that begins "and may include actions" should be removed because it is advisory in nature. The suggested actions are not even applicable under the scope of a vegetation management program.
Response: Thank you for your comment. The advisory type language has been removed from the requirement as you have suggested. The SDT also agrees that these "advisory" actions could fall outside the scope of some utilities' Transmission Vegetation Management Program. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system.		

Organization	Agree?	Question 7 Comment
Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any potential threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation		
San Diego Gas & Electric	Agree	We recommend that any advisory language be removed, and replaced with a declaration to the utilities.
Response: Thank you for your comment. The advisory type language has been removed from the requirement as you have suggested, The remaining declaratory language addresses the main purpose of the imminent threat requirement which is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any potential threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation		
WECC	Agree	But for clarity, "Imminent Threat Procedure" should be replaced with "Vegetation Imminent Threat Procedure".
Response: Thank you for your comment. The SDT believes that the context is sufficiently clear.		
Arizona Public Service Company	Agree	APS agrees with 1.4, with the following qualification: Any standard that is developed should not contain advisory-type language? it should be declarative in tone. For example, in R1.4, the ending clause that begins "and may include actions" should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program.
Response: Thank you for your comment. The advisory type language has been removed from the requirement as you have suggested. The SDT also agrees that these "advisory" actions could fall outside the responsibility of some utilities' Transmission Vegetation Management Program. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation.		
Baltimore Gas & Electric Company	Agree	This requirement references Danger trees which according to ANSI A-300, Part 7 is any tree that could fall on the conductor. Should this more appropriately be changed to Hazard tree which is a structurally unsound tree? It might be helpful if an imminent threat were defined, e.g. trees that are presently encroaching in or near the Critical Clearance Zone , or trees that by virtue of their hazardous condition appear to be likely to fall into or near the Critical Clearance Zone in the near future. (or just leave the explanation to the White Paper)

Organization	Agree?	Question 7 Comment
Response: Thank you for your comment. We agree with most of your comments and have made some major changes to this requirement due to the overwhelming response from industry that the imminent threat requirement was needed, as long as it was not an overly prescriptive requirement. Many situations can constitute an imminent threat, "danger" or "hazard" trees being only one of those situations. Further, due to the undefined "triggers" associated with the Critical Clearance Zone methodology, this approach has been removed from the Standard. **The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the "triggers", follow up activities, and procedures that best fit its situation. The SDT feels this is a better approach than to have a rigid definition of an imminent threat.**		
JEA	Agree	It is appropriate to require procedures to respond to "emergency" conditions; however Imminent Vegetation Threat should be a defined term.
Response: Thank you for your comment. The SDT prefers to allow the verbiage "an imminent threat of a vegetation-related Sustained Outage" to stand without further definition.		
BCTC	Agree	We agree with 1.4, with the following qualification: Any standard that is developed should not contain advisory-type language—it should be declarative in tone. For example, in R1.4, the ending clause that begins "…and may include actions…" should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program.
Response: Thank you for your comment. The advisory type language has been removed from the requirement as you have suggested. The SDT also agrees that these "advisory" actions could fall outside the responsibility of some utilities' Transmission Vegetation Management Program. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation.		
Great River Energy	Agree	GRE agrees and believes that it is very important for the applicable entities to posses an Imminent Threat Procedure. GRE recommends that the Imminent Threat procedure be renamed "Vegetation Imminent Threat Procedure" so as to clearly identify the procedure in the event that a company has imminent threat procedures for more than one situation.
Response: Thank you for your comment. We agree that many situations can constitute an imminent threat; however, the SDT did not rename the		

Organization	Agree?	Question 7 Comment
overall procedure as you have suggested. It is acceptable to have the imminent threat procedure for this standard included in a larger corporate procedure or set of procedures that address a wider array of threats. Instead the requirement has been rewritten to focus on the main purpose of the imminent threat requirement; which is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation. The SDT feels that this approach allows the Transmission Owner the flexibility to have imminent threat procedures for more than one situation which remain outside the specific requirements of the vegetation Standards.		
Santee Cooper	Agree	
Exelon	Agree	
Central Maine Power Company	Agree	
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
Kansas City Power & Light	Agree	
City of Tallahassee	Agree	
Northern California Power Agency (NCPA)	Agree	
Northern Indiana Public Service Company	Agree	
Long Island power Authority	Agree	
National Grid	Agree	

Organization	Agree?	Question 7 Comment
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
CenterPoint Energy	Agree	
Buckeye Power, Inc.	Agree	

8. Requirement 1 section R1.5 replaces Version 1 sub-requirement R1.4. This section is now referred to as interim corrective action process. This process addresses situations where vegetation maintenance activities cannot be performed as planned. The term corrective action plan is used in lieu of mitigation plan to avoid confusion with other uses in NERC of "mitigation plan". Do you agree with R1.5? If not, please explain.

Summary Consideration: Many of the stakeholders asked about the use of the word "interim" in R1.5 and what a constraint is. The SDT explains that 1.3 of the version 2 standard is intended to allow Transmission Owners to adjust the annual work plan to reflect such changes as a long term fix. Part 1.5 is intended to address an interim constraint such as customer refusals, governmental agency imposed restrictions, etc. To help clarify, the SDT added the word "temporarily" to the language noted in requirement R1.5. The SDT also added a new requirement R1.6 to address long term strategies.

1.5 Specify an interim corrective action process for use when the Transmission Owner is temporarily constrained from performing vegetation maintenance as planned.

1.6 Specify the maintenance strategies used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that Table 1 clearances in Attachment 1 are never violated. The maintenance strategies shall consider the sag and sway of the conductor throughout its operating range under rated conditions.

Organization	Agree?	Question 8 Comment
Western Area Power Administration, Rocky Mountain Region		The specifics of a "plan" as required by R1.4 in version 1 of the Standards has been replaced with the generalities of a "process" required by R1.5 in version 2 of the Standards. At the time of an audit, the adequacy of a general process is harder to measure than the adequacy of the specific mitigation measures that were previously required by R1.4 in version 1 of the Standards. It is unclear what an auditor will be looking for to determine compliance with R1.5 - will the auditor be looking for generalities or specifics? Further, if a utility has documented their interim corrective action process, but it is not followed, is this a violation of the Standards?
Response: Thank you for your comments. The SDT intended to require a documented process for Transmission Owners to develop plans which address instances such as customer refusals, government agency imposed constraints, etc. It is not intended solely for situations where initial desired clearances could not be achieved (as in requirement R1.4 of version 1 of FAC-003). The measure for Interim Corrective Action requires it be included in the Transmission Vegetation Management Program and failure to do so would be a violation.		
City of Tallahassee	Disagree	The use of the term "interim corrective action" implies that a permanent solution or return to the original plan must be pursued. I would change this to "alternate maintenance" process to prevent non-compliance if the Transmission Owner is constrained and has reached an agreement with the land owner that works to maintain

Organization	Agree?	Question 8 Comment
		the reliability of the line.
Response: Thank you for your comment. Requirement R1, Part 1.5 requires the Transmission Owner to specify a process in its Transmission Vegetation Management Program that the Transmission Owner may use when vegetation maintenance work is temporarily constrained. Constraints may include temporary situations such as caused by customer refusals, governmental agency imposed restrictions, etc. If a Transmission Owner reaches an agreement for "alternate maintenance" in these situations, Requirement R1,Part 1.3.3 allows for adjustment of the annual work plan. Alternative maintenance actions as suggested are now addressed in new Requirement R1,Part 1.6 as noted above in the consideration of comments to address long term maintenance strategies to ensure Table 1 clearance distances are never violated.		
Northern Indiana Public Service Company	Disagree	The existing R1.4 is focused on identifying where vegetation clearance objectives cannot be met at the time UVM work is performed due to restrictions outside of the Transmission Owner's immediate control. The proposed revised standard is focused on situations where work scheduled in the annual plan cannot be performed as planned for any reason. Can a constraint on planned work be internal such as budget related? Why bother with a corrective process for constrained planned work if the work not completed as planned poses no risk of causing an outage? I strongly believe that the sole focus of this provision must specifically address individual locations where, due to restrictions outside of the Transmission Owner owner's control, vegetation clearances specified in the Transmission Vegetation Management Program cannot be obtained. This section of the standard should be about trees being closer to conductors than they should be due to factors beyond the Transmission Owner's control, rather than whether or not planned work was performed.
Response: Thank you for your comments. Interim corrective actions are intended to address situations such as customer refusals, governmental agency imposed constraints, etc. Requirement R1, Part 1.3 requires that the annual work plan shall be documented and Requirement R1, Part 1.3.3 permits adjustments to the annual work plan. A Requirement R1, Part 1.6 was added to address long term maintenance strategies to ensure Table 1 clearance distances are never violated.		
Tampa Electric Company	Disagree	The phrasing above references a "corrective action plan". However, the standard as written is stated as an "interim corrective action process". These are not one and the same. Interim implies a truly temporary condition. As described on page 21 of the Technical reference, however, some of these operational issues may not be "interim".
Response: Thanks for your comments. The SDT agree that "interim" should have been included in the question. The Technical Reference document does not appear to be in conflict with this. To add clarity the SDT added the word temporarily to Requirement R1, Part 1.5 and long term strategies are addressed in new Requirement R1, Part 1.6 a to address long term maintenance strategies to ensure Table 1 clearance distances are never violated.		
Manitoba Hydro	Disagree	Agree with the change in terminology - but would suggest that wording clarify that this is not only for situations where the utility is unexpectedly prevented from implementing its annual plan - but also for areas where it is

Organization	Agree?	Question 8 Comment
		unable to implement its clearance requirements due to property rights limitations.
Response: Thank you for your comment. Requirement R1, Part 1.5 requires the Transmission Owner to specify a process in its Transmission Vegetation Management Program that the Transmission Owner may use when vegetation maintenance work is <u>temporarily</u> constrained. Constraints may include temporary situations such as caused by customer refusals, governmental agency imposed restrictions, etc. Requirement R1, Part 1.6 was added to address long term maintenance strategies to ensure Table 1 clearance distances are never violated.		
National Grid	Disagree	National Grid agrees replacing mitigation plan with corrective action process. However, National Grid questions the use of "interim" for a corrective action process in R1.5, and suggests striking "interim".
Response: Thank you for your comment. Requirement R1, Part 1.5 requires the Transmission Owner to specify a process in its Transmission Vegetation Management Program that the Transmission Owner may use when vegetation maintenance work is <u>temporarily</u> constrained. Constraints may include temporary situations such as caused by customer refusals, governmental agency imposed restrictions, etc. To add clarity the SDT added the word "temporarily" to Requirement R1, Part 1.5.		
CenterPoint Energy	Disagree	Since there is no longer a reference to defined clearances in the Standard, it is unclear under what specific "constrained" conditions R1.5 applies. R1.5 does not have a sister requirement for implementation within the Standard which implies it has a diminished value. R1.5 and M1.5 should be deleted as a requirement and measure, but should be footnoted as best practice as was ANSI A300 in R1.1.
Response: Thank you for your comments. The SDT intended to require a documented process for Transmission Owners to develop plans which address instances such as customer refusals, government agency imposed constraints, etc. It is not intended solely for situations where initial desired clearances could not be achieved (as in requirement R1.4 of version 1 of FAC-003). A new Requirement R1, Part1.6 was added to address long term maintenance strategies to ensure Table 1 clearance distances are never violated.		
American Transmission Company	Agree	ATC agrees with the concept but disagrees with the proposed language. ATC believes the term "interim" should be removed from R 1.5. In some cases, a corrective action can end up being a long term/normal fix. Proposed Language: Specify a corrective action process that will be used when established clearances or methodologies are altered.
Response: Requirement R1, Part 1.3 requires that the annual work plan shall be documented. Requirement R1, Part 1.3.3 permits adjustments to the annual work plan. A long term fix would be an adjustment to the annual work plan. In Requirement R1, Part 1.5, the SDT intended to require a documented process for Transmission Owners to develop plans which address instances such as customer refusals, government agency imposed constraints, etc. It is not intended solely for situations where initial desired clearances could not be achieved (as in requirement R1.4 of version 1 of FAC-003). To add clarity the SDT added the word "temporarily" to Requirement R1, Part 1.5. Long term strategies are addressed in new requirement R1.6 as noted above in the consideration of comments to address long term maintenance strategies to ensure Table 1 clearance distances are never		

Organization	Agree?	Question 8 Comment
violated.		
Southern California Edison Company	Agree	Q8: SCE agrees in part with the revisions to R1.5, including the proposed phrase "corrective action process". However, we do not believe it is necessary to include the term "Transmission Owner" in the sentence because the entire standard is clearly applicable to Transmission Owners. SCE respectfully suggests that proposed R1.5 be revised to read: "Specify an interim corrective action process for use when planned vegetation maintenance is deferred."
Response: Thank you for your comment. The SDT considered your suggested language and feels the language used in the draft standard is appropriate in order to maintain consistency with other parts of the standard.		
Western Utility Arborists	Agree	Yes, we agree.
Response: Thank you for your participation.		
FirstEnergy	Agree	We agree with the concept of a corrective action plan. However, it is not clear what flexibility the Transmission Owner is afforded in making adjustments to the work plan that may carry over from one calendar year to the next. Legal issues with property owners or other factors may prevent the utility from carrying out the work plan as scheduled. Also, we question the use of the term "constrained". It should be clear as to what constitutes appropriate or valid constraints.
Response: Thank you for your comments. Requirement R1, Part 1.3.3 permits adjustments to the annual work plan. As to your next concern, Requirement R1, Part 1.5 requires the Transmission Owner to specify a process in its Transmission Vegetation Management Program that the Transmission Owner may use when vegetation maintenance work is temporarily constrained. Constraints may include temporary situations such as caused by customer refusals, governmental agency imposed restrictions, etc. Refer to the Technical Reference document for additional information.		
MRO NERC Standards Review Subcommittee	Agree	The MRO believes that the term "interim" should be removed from R1.5. The term Interim is subjective.
Response: Thank you for your comment. The SDT uses “interim” to convey the temporary nature of these situations. To add clarity the SDT added the word “temporarily” to Requirement R1. Part 1.5 and a new Requirement R1, Part 1.6 was added to address long term maintenance strategies to ensure Table 1 clearance distances are never violated.		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 8
Response: Thank you for your participation.		

Organization	Agree?	Question 8 Comment
Platte River Power Authority	Agree	The term corrective action plan adds clarity.
Response: Thank you for your participation.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	In my opinion, problems between the Transmission Owner and the USFS over the Transmission Vegetation Management Program should be worked out before a Transmission Vegetation Management Program is ever finalized. A dispute resolution process outside the control of either party would be very helpful and would probably facilitate quicker solutions than if the Transmission Owner and the USFS are left to work out problems on their own. If a Transmission Vegetation Management Program is prepared in a vacuum, the problems may not come to light until some kind of outage actually occurs. It would be much better to flush any disagreements and deal with them before any outages actually occur.
Response: Thank you for your comment. We agree with the sentiment of collaboration and cooperation expressed. We are somewhat constrained by the types of entities that must be subject to this standard. The USFS, as a government agency, is not under the purview of the FERC and is not compelled to comply with this standard however well intended. The SDT would support a dispute resolution process that resolves potential disagreements consistent with the purpose of this standard.		
BCTC	Agree	Yes, we agree.
Response: Thank you for your participation.		
Great River Energy	Agree	GRE believes that the term "interim" should be removed from R1.5. The term Interim is subjective.
Response: Thank you for your comment. Requirement R1, Part 1.5 requires the Transmission Owner to specify a process in its Transmission Vegetation Management Program that the Transmission Owner may use when vegetation maintenance work is temporarily constrained. Constraints may include temporary situations such as caused by customer refusals, governmental agency imposed restrictions, etc. To add clarity the SDT added the word temporarily to Requirement R1, Part 1.5 and long term strategies are addressed in new Requirement R1, Part1.6 to address long term maintenance strategies to ensure Table 1 clearance distances are never violated.		
Progress Energy Carolinas	Agree	
Associated Electric Cooperative Inc.	Agree	
NPCC	Agree	

Organization	Agree?	Question 8 Comment
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
SERC Vegetation Management Subcommittee (VMS)	Agree	
Progress Energy Florida	Agree	
Kansas City Power & Light	Agree	
SERC OC Standards Review Group	Agree	
Florida Power & Light	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
Bonneville Power Administration	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	

Organization	Agree?	Question 8 Comment
Exelon	Agree	
Central Maine Power Company	Agree	
American Electric Power (AEP)	Agree	
Northern California Power Agency (NCPA)	Agree	
Orange and Rockland Utilities Inc.	Agree	
Ameren	Agree	
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Consumers Energy Company	Agree	
Pacific Gas & Electric Co.	Agree	
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	
San Diego Gas & Electric	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	

Organization	Agree?	Question 8 Comment
WECC	Agree	
Arizona Public Service Company	Agree	
Baltimore Gas & Electric Company	Agree	
Duke Energy Corporation	Agree	
Entergy Services	Agree	
Pepco Holdings, Inc	Agree	
JEA	Agree	
Independent Electricity System Operator	Agree	
Salt River Project	Agree	
Northeast Utilities	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
Buckeye Power, Inc.	Agree	

9. **Clearance 1 in Version 1 was a "fill-in-the-blank" requirement and was removed from the standard. Do you agree? If not, please explain.**

Summary Consideration: Most of the industry comments are in favor of removing the "fill-in-the-blank" requirement. Some disagreed, citing the benefit of having perceived leverage that a Clearance 1 afforded them. The SDT points out that ANSI A300 remains a "best practice" referenced in the proposed standard and may be useful in dealing with public and private parties. In addition, the SDT added Requirement R1.6:

1.6 Specify the maintenance strategies used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that Table 1 clearances in Attachment 1 are never violated. The maintenance strategies shall consider the sag and sway of the conductor throughout its operating range under rated conditions.

The SDT believes that Clearance 1 may be unnecessarily restrictive in stipulating conductor-to-vegetation distances (as some commenters have done to comply) and therefore removed Clearance 1 in favor of Requirement R1, Part 1.6. which specifically allows for vegetation-to-ground distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions.

Organization	Agree?	Question 9 Comment
Florida Power & Light		FPL neither agrees or disagrees with this removal but provides the following comment. FPL's experience regarding Clearance 1 is that it was an effective way of demonstrating a measurable requirement for compliance when dealing with public entities. The use of a corrective action process to mitigate instances where this clearance was not met before violations occurred is also very effective in promoting reliability and safety in the Standard.
Response: Thank you for your comment. The SDT team acknowledges the comment with regard to the usefulness of Clearance 1 in dealing with public entities and has attempted to retain that capability in Requirement R1, Part 1.6. Furthermore the use of a corrective action process is retained in this latest version but is renamed as an "interim correction action" in lieu of "Mitigation Plan" to avoid confusion with a Compliance Program term.		
Western Utility Arborists	Disagree	The Western Utilities do not agree with the removal of Clearance 1. We recommend adding it back to the document, but reworded and moved to include it as a measurement (M), rather than a requirement (R) under the new standard. Many utilities feel that Clearance 1 provides justification and leverage for operational clearances when dealing with organizations such as municipalities. Without Clearance 1, utilities could be mandated in specific situations to clear so that the vegetation is just beyond the Critical Clearance Zone at all times. This could result in pruning at six month intervals, which is not feasible or cost-effective.

Organization	Agree?	Question 9 Comment
Response: Thank you for your comment. The SDT notes that information contained in a Measure would not be mandatory nor enforceable and therefore has minimal usefulness as leverage. The SDT points out that ANSI A300 remains a "best practice" referenced in the proposed standard and may be useful in dealing with the public and private parties. The addition of Requirement R1, Part 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		
Bonneville Power Administration	Disagree	BPA opposes removal of Clearance 1. Clearance 1 provides a regulatory justification for a Transmission Owner to apply and extend proactive vegetation threat prevention programs on its rights of way easements across municipal, state, tribal, other federal and private properties. In many cases, without the regulatory leverage of a Clearance 1 requirement, Transmission Owners would be limited to maintaining less effective and higher risk vegetation management practices where it has legal restrictions, then it presently can implement under the present version of FAC 003-01. BPA recommends that Clearance 1 be placed back into the document, but as a Measure and not a Requirement.
Response: Thank you for your comment. The SDT notes that information contained in a Measure would not be mandatory nor enforceable and therefore has minimal usefulness as leverage. The SDT points out that ANSI A300 remains a "best practice" referenced in the proposed standard and may be useful in dealing with the public and private parties. The addition of Requirement R1, Part 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		
Exelon	Disagree	We do not understand the reference to "fill in the blank" requirement for clearance 1. As commonly understood, a "fill in the blank" standard /requirement is one that was assigned to the RRO. Clearance 1 in FAC-003-1 is a Transmission Owner requirement. The reference to a clearing zone should be retained, as each Transmission Owner will need to define this in their program so as to avoid encroachments into the Critical Clearance Zone .
Response: Thank you for your comment. The choice of a Clearance 1 distance is left to each Transmission Owner and as such is characterized as a fill-in-the blank style requirement. The SDT team believes each Transmission Owner is free to set any working distances it deems appropriate in order to accomplish its Transmission Vegetation Management Program objectives.		
Central Maine Power Company	Disagree	Central Maine Power Company disagrees with removal of clearance 1. The clearance 1 was included so that professional arborists could establish the clearance necessary for a transmission owner to reduce the risk of a tree caused power outage. The transmission owner should use ANSI- Standard A300, including PART 7, and other publications to develop best management practices which include clearances at time of maintenance. Clearance 1 provides leverage for Transmission Owners to achieve the clearances stated in their Transmission

Organization	Agree?	Question 9 Comment
		Vegetation Management Program.
Response: Thank you for your comment. The SDT notes that information contained in a Measure would not be mandatory nor enforceable and therefore has minimal usefulness as leverage. The SDT points out that ANSI A300 remains a "best practice" referenced in the proposed standard and may be useful in dealing with the public and private parties. The addition Requirement R1, Part 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Disagree	If it is possible for NERC to identify minimum clearance standards as related to arcing potential for hazardous vegetation, it would definitely help USFS field administrators to have some kind of hard and fast standards. If that kind of approach is not reasonable in light of the need to adjust standards for various load conditions and vegetation growth rates, then a prescribed formula for calculating minimum clearances would be the next best thing.
Response: Thank you for your comment. The SDT proposes the table of Minimum Vegetation Clearance Distances in this revised version of the standard in Requirement R4, which prohibits vegetation encroachment inside minimum vegetation clearance distances that are developed with Gallet equations for flashover (arcing).		
National Grid	Disagree	National Grid takes exception to the term "fill-in-the-blank". National Grid disagrees with the elimination of Clearance 1. The Clearance 1 requirement in FAC-003-1 was meant to allow a Transmission Owner to establish clearances to be achieved at the time of vegetation management work, and be sensitive to local and regional conditions. National Grid believes that Clearance 1 is needed for public education and safety reasons. Clearance 1 standards allow utilities to specify a cyclic programmatic approach, and gives the utility leverage with local and state regulators and the public to achieve significantly larger than minimal clearances.
Response: Thank you for your comment. The choice of a Clearance 1 distance is left to each Transmission Owner and as such is characterized as a fill-in-the blank style requirement. The SDT team believes each Transmission Owner is free to set any working distances it deems appropriate in order to accomplish its Transmission Vegetation Management Program objectives. The SDT points out that ANSI A300 remains a "best practice" referenced in the proposed standard and may continue to be useful in dealing with the public and private parties. The addition of Requirement R1, Part 1.6 allows for vegetation-to-ground working distances which can be larger than minimal clearances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		

Organization	Agree?	Question 9 Comment
Platte River Power Authority	Disagree	Clearance 1 could be defined in the standard in tables developed using IEEE Standards for various voltages, line spans and altitudes. Clearance 1 provides justification and leverage for operational clearances when dealing with organizations such as municipalities. Without Clearance 1, utilities could be mandated in specific situations to clear so that the vegetation is just beyond the Critical Clearance Zone at all times. This could result in pruning at six month intervals, which is not feasible or cost-effective.
Response: Thank you for your comment. The SDT proposes the table of Minimum Vegetation Clearance Distances in this revised version of the standard in Requirement R4, which prohibits vegetation encroachment inside minimum vegetation clearance distances that are developed with Gallet equations for flashover (arcing). The SDT points out that the ANSI A300 remains a "best practice" referenced in the proposed standard and may be useful in dealing with the public such as municipalities and private parties. The addition of Requirement R1, Part 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		
Northern Indiana Public Service Company	Disagree	I am strongly opposed to the removal of Clearance 1 from the standard. Being able to point to this provision has been invaluable to internal communications with upper management and external discussions with land owners and the public concerning UVM. In fact, other than the patrol/inspection requirements, no other provision in the standard has been as essential to preventing grow-in tree contacts than Clearance 1. It has forced Transmission Owner's across the country to re-claim overgrown ROW and re-commit to consistent UVM practices. We all know how easy it is for Transmission Owner's to get weak in the knees in the face of public opposition to proper and prudent UVM work even when it is clear what needs to be done. This dynamic is what led us to the 2003 blackout to begin with. I would like to see the drafting team consider expanding upon the existing model and create three clearances: 1. A clearance at the time work is performed, 2. An action threshold clearance which would trigger the Transmission Owner would take immediate action to clear encroaching vegetation posing an unacceptable outage risk, and 3. A no closer than clearance in which vegetation would never be allowed to encroach in order to prevent flashover.
Response: Thank you for your comment. The SDT team acknowledges the comment with regard to the usefulness of Clearance 1 to internal communications and in dealing with public entities and has attempted to retain that capability Requirement R1. Part 1.6. The addition of Requirement R1, Part 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		

Organization	Agree?	Question 9 Comment
In regard to working distances or as you put it , each Transmission Owner continues to able to set any working distances it deems appropriate in order to accomplish its Transmission Vegetation Management Program objectives when complying with Requirement R1, Part 1.6. **With respect to your 3rd comment, the proposed version of the standard has Requirement R4, which prohibits vegetation encroachment inside Minimum Vegetation Clearance Distances that are developed with Gallet equations for flashover.**		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Disagree	We do not agree with the removal of Clearance 1. We recommend adding it back to the document, but reworded and moved to include it as a measurement (M), rather than a requirement (R) under the new standard. Many utilities feel that Clearance 1 provides justification and leverage for operational clearances when dealing with organizations such as municipalities. Without Clearance 1, utilities could be mandated in specific situations to clear so that the vegetation is just beyond the Critical Clearance Zone at all times. This could result in pruning at six month intervals, which is not feasible or cost-effective.
Response: Thank you for your comment. The SDT notes that information contained in a Measure would not be mandatory nor enforceable and therefore has minimal usefulness as leverage. The SDT points out that ANSI A300 remains a “Best Practice” referenced in the proposed standard and may be useful in dealing with the public and private parties. The addition of Requirement R1, Part 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		
San Diego Gas & Electric	Disagree	We do not agree with the removal of Clearance 1. We recommend that it be added back into the document, but reworded and moved so it be included as a measurement, rather than a requirement. Without Clearance 1, utilities could be mandated in specific situations to clear so that vegetation is just beyond the Critical Clearance Zone at all times, which is not feasible or cost effective.
Response: Thank you for your comment. The SDT notes that information contained in a Measure would not be mandatory nor enforceable and therefore has minimal usefulness as leverage. The SDT points out that ANSI A300 remains a “Best Practice” referenced in the proposed standard and may be useful in dealing with the public and private parties. The addition of Requirement R1, Paart 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		
Hydro One Networks Inc.	Disagree	We would agree only if the standard is revised to include the removal of incompatible vegetation as outlined in our response to question 3 above. If not, then added direction or requirements are needed to introduce the elements that combine (to a greater degree than exists under the revised standard) reliability and vegetation management. Clearance 1 accomplished this to some degree.

Organization	Agree?	Question 9 Comment
Response: Thank you for your comment. The SDT considered the insertion of the phrase "incompatible vegetation" however decided against it because incompatibility may be arguable and add to disagreement among interested parties. The SDT agrees with the commenter that all vegetation that is identified by the annual work plans and maintenance strategies should be targeted for removal. Each Transmission Owner is free to use any effective approach it deems appropriate in order to accomplish its Transmission Vegetation Management Program objectives. The proposed version of the standard has Requirement R4, which prohibits vegetation encroachment inside Minimum Vegetation Clearance Distances that are developed with Gallet equations for flashover.		
Arizona Public Service Company	Disagree	APS disagrees with removal of clearance one. Clearance one should be achieved at time of maintenance which is part of the vegetation program. This gives leverage with dealing with state and federal agencies, tribal and private landowners. This isn't a fill in the blank requirement, however it should be based on sound science in regards to vegetation management. A professional arborist/forester can determine the appropriate amount of vegetation that needs to be obtained at the time of maintenance. APS suggest the following language change for clearance 1. The Transmission Owner shall maintain ROW on Federal, State, Tribal and Private lands in accordance with ANSI-Standard A300 (Part 1)-2001 and (Part 7)-2006 in consultation with companion publication Best Management Practices: Integrated Vegetation Management, 2007. If all utilities followed this standard this would increase the reliability of the bulk electric system and reduce the risk of vegetation outages.
Response: Thank you for your comment. The SDT agrees that any requirement must be based on sound science and believes the Transmission Owner will continue to able to set any working distances it deems appropriate in order to accomplish its Transmission Vegetation Management Program objectives when complying with Requirement R1, Part 1.6. The stipulation that the Standard applies to Federal, State, Tribal and Private Lands is contained in the Applicability section. The SDT points out that ANSI A300 remains a "best practice" referenced in this standard and as such may be useful in dealing with state and federal agencies, tribal and private landowners, etc.		
BCTC	Disagree	BCTC do not agree with the removal of Clearance 1. We recommend adding it back to the document, but reworded and moved to include it as a measurement (M), rather than a requirement (R) under the new standard. Many utilities feel that Clearance 1 provides justification and leverage for operational clearances when dealing with organizations such as municipalities. Without Clearance 1, utilities could be mandated in specific situations to clear so that the vegetation is just beyond the Critical Clearance Zone at all times. This could result in pruning at six month intervals, which is not feasible or cost-effective.
Response: Thank you for your comment. The SDT notes that information contained in a Measure would not be mandatory nor enforceable and therefore has minimal usefulness as leverage. The SDT points out that ANSI A300 remains a "best practice" referenced in the proposed standard and may be useful in dealing with the public and private parties. The addition of Requirement R1, Part 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		

Organization	Agree?	Question 9 Comment
Salt River Project	Disagree	Recommend adding it back to the document, however, only if it is changed to become a measurement (M) rather than a requirement (R). Leaving it in as a measurement provides justification and leverage for operational clearances when dealing with landowners. Without Clearance 1 landowners may only allow vegetation clearance just at the Critical Clearance Zone at all times, which is not a feasible, cost-effective, or responsible way for utilities to manage vegetation clearance.
Response: Thank you for your comment. The SDT notes that information contained in a Measure would not be mandatory nor enforceable and therefore has minimal usefulness as leverage. The SDT points out that ANSI A300 remains a “best practice” referenced in the proposed standard and may be useful in dealing with the public and private parties. The addition of Requirement R1, Part 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		
American Electric Power (AEP)	Agree	AEP agrees with the removal of Clearance 1 from the Standard.
Response: Thank you for your comment.		
NPCC	Agree	We agree but believe that the Transmission Vegetation Management Program should target removal of all incompatible vegetation on the Active Right of Way as described in the response to question 3.
Response: Thank you for your comment. The SDT agrees with the commenter that any vegetation located within the Active Transmission Line ROW should be targeted for removal using means and strategies described in its Transmission Vegetation Management Program.		
Western Area Power Administration, Upper Great Plains Region	Agree	While Western (UGPR) agrees with the removal of Clearance 1, we believe it is advantageous for Transmission Owners to have a "trigger distance" in order to have some additional time to plan and schedule vegetation work. The trigger distance is advantageous only if the Regulators do NOT interpret it to be an extended Critical Clearance Zone and do NOT enforce based on "trigger distance" instead of the Critical Clearance Zone .
Response: Thank you for your comment. The SDT team believes the addition of Requirement R1, Part 1.6 continues to allow each Transmission Owner to set any working distances it deems appropriate in order to accomplish the objectives with this Standard. This Requirement 1 Part 1.6 is superior to Clearance 1 as it gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		
MRO NERC Standards Review Subcommittee	Agree	The MRO agrees and fully supports the removal of Clearance 1. The MRO believes that the Gallet equation is a more effective way of determining the required clearances.

Organization	Agree?	Question 9 Comment
Response: Thank you for your comment.		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 9
Response: Thank you for your comment.		
Orange and Rockland Utilities Inc.	Agree	We generally agree, however please see comments included in question 18.
Response: Thank you for your comment.		
Baltimore Gas & Electric Company	Agree	While I may agree with the removal of this requirement strictly for reasons of simplification and self-determination, the current requirement forced utilities to structure their Transmission Vegetation Management Program to develop safeguards to keep trees from encroaching into the Clearance 2 envelope. The proposed change will leave the clearance issue beyond the Critical Clearance Zone unaddressed. Responsible utilities will take the appropriate measures and other utilities will not.
Response: Thank you for your comment. Each Transmission Owner is free to use any effective approach it deems appropriate in order to accomplish its Transmission Vegetation Management Program objectives. The SDT believes there are significant disincentives against the behavior you warn about in the revised version.		
CenterPoint Energy	Agree	Designation of Clearance 1 is not required to meet the purpose of the Standard.
Response: Thank you for your comment.		
Hydro-Quebec Transenergie (HQT)	Agree	We agree but believe that the Transmission Vegetation Management Program should target removal of all incompatible vegetation on the Active Right of Way as described in the response to question 3.
Response: Thank you for your comment. The SDT agrees with the commenter that any vegetation that are located within the Active Transmission Line ROW should be targeted for removal using means and strategies described in its Transmission Vegetation Management Program.		
Great River Energy	Agree	GRE agrees and fully supports the removal of Clearance 1. GRE believes that the Gallet equation is a more effective way of determining the required clearances.
Response: Thank you for your comment.		

Organization	Agree?	Question 9 Comment
Southern California Edison Company	Agree	Q9: No comments.
Associated Electric Cooperative Inc.	Agree	
WECC Reliability Coordination	Agree	
SERC Vegetation Management Subcommittee (VMS)	Agree	
Progress Energy Florida	Agree	
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Progress Energy Carolinas	Agree	
SERC OC Standards Review Group	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
FirstEnergy	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	

Organization	Agree?	Question 9 Comment
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	
City of Tallahassee	Agree	
Northern California Power Agency (NCPA)	Agree	
Tampa Electric Company	Agree	
American Transmission Company	Agree	
Ameren	Agree	
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Manitoba Hydro	Agree	
Consumers Energy Company	Agree	
Pacific Gas & Electric Co.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Entergy Services	Agree	

Organization	Agree?	Question 9 Comment
Pepco Holdings, Inc	Agree	
JEA	Agree	
Northeast Utilities	Agree	
Independent Electricity System Operator	Agree	
Duke Energy Corporation	Agree	
Buckeye Power, Inc.	Agree	

10. Personnel Qualifications in R1.3 in Version 1 was a "fill-in-the-blank" requirement and was removed from Version 2 of the standard. Do you agree? If not please explain.

Summary Consideration: Most commenters agree with the deletion of R1.3 from the approved standard. The" fill in the blank" requirement that was included in version 1 allowed the Transmission Owner to set its own standard for personnel qualifications rather than require the same set of qualifications for personnel in all entities. The SDT recommended removing the requirement as it is not enforceable and recommended against replacing the "fill-in-the-blank" element with a continent-wide set of personnel qualifications. The SDT believes that any set of personnel qualifications enforced on a continent-wide basis would result in a set of "lowest common denominator" qualifications that would be too stringent for some entities, and too lax for others – with no apparent reliability benefit. Instead, the SDT recommended letting entities set their own internal personnel qualifications to best meet their own needs.

Organization	Agree?	Question 10 Comment
Central Maine Power Company	Disagree	Central Maine Power Company disagrees with the removal of the qualification statement. The individual responsible for this critical program must be qualified through experience, training, and education. The International Society of Arboriculture has a certification program that can help with guidelines for qualified arborists.
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard, remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
Northern Indiana Public Service Company	Disagree	If the standard continues to allow T.O.'s to design and implement their own TVMPs and expect them to use BMPs, ANSI A300, develop methods and practices, adapt schedules and plans to changing conditions, etc., then it is reasonable to expect that T.O. personnel responsible for the TVMP to be experts in the field of utility vegetation management with appropriate training, certifications, licenses and credentials. I do not agree with eliminating this requirement. Quite the opposite, I believe that the requirement needs to be more specific as to minimum qualifications key personnel must meet. There are more requirements & qualifications to drive a semi-truck than to design and implement a program (UVM) critical to the operation of the nation's electric grid. Does that make sense?
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard, remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
USDA Forest Service, Southwestern Region, Regional	Disagree	Perhaps standard M8 could be expanded or clarified to require the Transmission Owner to describe how employees, especially field supervisors, are trained to implement the plan and to prove that the training was

Organization	Agree?	Question 10 Comment
Office for AZ and NM		actually provided. Some problems have arisen in the USFS Southwestern Region because some Transmission Owners are not providing adequate supervision of field work.
Response: The SDT thanks you for your comment. The requirement that was dropped between the version 1 and version 2 spoke to the qualifications of development and implementation of the TVMP and not the adequacy of the field supervision. This does not relieve the TO from providing adequate field supervision.		
National Grid	Disagree	National Grid takes exception to the term “fill-in-the-blank”. National Grid would like Personnel Qualifications to remain in Standard FAC-003-2.
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard, remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
San Diego Gas & Electric	Disagree	We feel there must be appropriate knowledge to do the work, and that Transmission Owners must at least have internal standards related to personnel qualifications.
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard, remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
Arizona Public Service Company	Disagree	APS disagrees with the removal of personnel qualifications. The person responsible for vegetation management program should have experience and training in vegetation management and system operations. The International Society of Arboriculture has an ISA Certified Arborist and Utility Specialist certification. This requires the credential holder to have minimal qualifications before sitting for the certification and on going training to maintain the credential. The industry has already responded by providing the information as part of the current standard FAC-003-1. It makes no sense to remove personnel qualifications from the revision.
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard, remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
British Columbia Transmission Corp.	Disagree	BCTC does not agree with the elimination of this requirement. We feel strongly there must be appropriate knowledge to do the work, and that Transmission Owners must have internal standards related to personnel qualifications. We understand that several utilities would like this requirement removed because it created problems in the auditing process. It is unfortunate that this important requirement for an effective vegetation management program has been removed due misapplication of the intent during audits.
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard,		

Organization	Agree?	Question 10 Comment
remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
Central Maine Power Company	Disagree	Central Maine Power Company disagrees with the removal of the qualification statement. The individual responsible for this critical program must be qualified through experience, training, and education. The International Society of Arboriculture has a certification program that can help with guidelines for qualified arborists.
Response: The SDT thanks you for your response. While we agree that the International Society of Arboriculture certifications are credible qualifications for a large work force, these same programs may be too stringent and unnecessary for utilities only needing a very small work force. **It is unknown if certification by ISA or similar organizations has impacted reliability for any Transmission Owner.**		
Northern Indiana Public Service Company	Disagree	If the standard continues to allow T.O.'s to design and implement their own Transmission Vegetation Management Programs and expect them to use BMPs, ANSI A300, develop methods and practices, adapt schedules and plans to changing conditions, etc., then it is reasonable to expect that T.O. personnel responsible for the Transmission Vegetation Management Program to be experts in the field of utility vegetation management with appropriate training, certifications, licenses and credentials. I do not agree with eliminating this requirement. Quite the opposite, I believe that the requirement needs to be more specific as to minimum qualifications key personnel must meet. There are more requirements & qualifications to drive a semi-truck than to design and implement a program (UVM) critical to the operation of the nation's electric grid. Does that make sense?
Response: The SDT thanks you for your response. The SDT concurs that some Transmission Vegetation Management Programs are highly complex and would require highly trained arborists and vegetation management personnel to develop such programs. However, there are many programs that are substantially less complex and do not require that level of expertise. We feel that utilities with complex programs would by nature acquire appropriately trained personnel to implement their programs.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Disagree	Perhaps standard M8 could be expanded or clarified to require the Transmission Owner to describe how employees, especially field supervisors, are trained to implement the plan and to prove that the training was actually provided. Some problems have arisen in the USFS Southwestern Region because some Transmission Owners are not providing adequate supervision of field work.
Response: The SDT thanks you for your comment. The requirement that was dropped between the version 1 and version 2 spoke to the qualifications of development and implementation of the Transmission Vegetation Management Program and not the adequacy of the field supervision.		
National Grid	Disagree	National Grid takes exception to the term "fill-in-the-blank". National Grid would like Personnel Qualifications

Organization	Agree?	Question 10 Comment
		to remain in Standard FAC-003-2.
Response: The SDT thanks you for your response. A" fill in the blank" requirement as stated in version 1 allowed the Transmission Owner to set its own standard and does not substantively add to the effectiveness of the Standard.		
British Columbia Transmission Corp.	Disagree	BCTC does not agree with the elimination of this requirement. We feel strongly there must be appropriate knowledge to do the work, and that Transmission Owners must have internal standards related to personnel qualifications. We understand that several utilities would like this requirement removed because it created problems in the auditing process. It is unfortunate that this important requirement for an effective vegetation management program has been removed due misapplication of the intent during audits.
Response: The SDT thanks you for your response. A" fill in the blank" requirement as stated in version 1 allowed the Transmission Owner to set its own standard and does not substantively add to the effectiveness of the Standard.		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 10
Response: The SDT thanks you for your response.		
Exelon	Agree	Agree but same comment as above, we do not understand the reference to "fill in the blank" requirement for R1.3. As commonly understood, a "fill in the blank" standard /requirement is one that was assigned to the RRO.
Response: The SDT thanks you for your response. A" fill in the blank" requirement as stated in version 1 allowed the TO to set its own standard as opposed to RRO. In either case the concept of a "fill in the blank requirement" does not substantively add to the effectiveness of the Standard.		
Tampa Electric Company	Agree	While we agree with the removal of "fill-in the blank" requirements, we recommend the inclusion of professional qualifications for staff involved in this Standard. Reading the 42 page technical reference and the attached comment form, all involved need to really understand the Standard as well as industry practices.
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard, remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
Baltimore Gas & Electric Company	Agree	Similar to the response to no. 9, the end result is what counts and each utility will be responsible and accountable for their actions. Qualifications unlike clearance requirements, are far-removed from results and can easily be left unaddressed in the new std.

Organization	Agree?	Question 10 Comment
Response: The SDT thanks you for your response.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	We are in agreement with the elimination of this requirement, but not without some qualifications. We feel strongly there must be appropriate knowledge to do the work, and that Transmission Owners must at least have internal standards related to personnel qualifications. It is unfortunate that this important requirement for an effective vegetation management program has been removed due to concerns with the auditing program.
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard, remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
CenterPoint Energy	Agree	Designation of Personnel Qualifications are not required to meet the purpose of the Standard.
Response: The SDT thanks you for your response.		
American Electric Power (AEP)	Agree	AEP agrees that the Standard should not stipulate or require personnel qualifications.
Response: The SDT thanks you for your response.		
Platte River Power Authority	Agree	The requirement should be removed because it is a "fill-in-the-blank" requirement. Defining the proper amount of personnel qualifications and training would be too prescriptive for utilities with small vegetation management programs and not prescriptive enough for utilities with large vegetation management programs.
Response: The SDT thanks you for your comments.		
Western Utility Arborists	Agree	The Western Utilities are in agreement with the elimination of this requirement. However, we feel strongly there must be appropriate knowledge to do the work, and that Transmission Owners must at least have internal standards related to personnel qualifications.
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard, remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
Southern California Edison Company	Agree	Q10: No comments.
SERC OC Standards Review	Agree	

Organization	Agree?	Question 10 Comment
Group		
Florida Power & Light	Agree	
Santee Cooper	Agree	
Progress Energy Carolinas	Agree	
SERC Vegetation Management Subcommittee (VMS)	Agree	
Progress Energy Florida	Agree	
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
City of Tallahassee	Agree	
Northern California Power Agency (NCPA)	Agree	
Long Island power Authority	Agree	
Manitoba Hydro	Agree	
Consumers Energy Company	Agree	
Pacific Gas & Electric Co.	Agree	
Duke Energy Corporation	Agree	
Associated Electric Cooperative	Agree	

Organization	Agree?	Question 10 Comment
Inc.		
NPCC	Agree	
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
Orange and Rockland Utilities Inc.	Agree	
American Transmission Company	Agree	
Ameren	Agree	
Nebraska Public Power District	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Entergy Services	Agree	
Pepco Holdings, Inc	Agree	
JEA	Agree	

Organization	Agree?	Question 10 Comment
Independent Electricity System Operator	Agree	
Salt River Project	Agree	
Northeast Utilities	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
Buckeye Power, Inc.	Agree	
Great River Energy	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
Bonneville Power Administration	Agree	
FirstEnergy	Agree	
MRO NERC Standards Review Subcommittee	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	

11. The IEEE 516 standard distances were replaced with the Gallet equation distances. Clearance 2 was replaced by the Critical Clearance Zone. The Critical Clearance Zone is defined as the zone of all possible positions of the conductor at the line's designed operating ratings including wind factors. (Please refer to pages 22-32 in the Technical Reference Document on the Critical Clearance Zone for further background for this question.) The imminent threat procedure, R2, requires action to be taken to prevent an outage when the Critical Clearance Zone is approached. Do you agree with R2? If not please explain.

Summary Consideration: The majority of responders (61%) disagreed with the concept of the imminent threat procedure being associated with the Critical Clearance Zone (CCZ). The key concerns that commenters raised were associated with the Critical Clearance Zone and included the following:

- It is a good concept but is theoretical and difficult to administer in the field
- Respondents preferred a more defined distance that is real-time and measurable
- The word "approach" caused concern due to being vague and open to interpretation

Although there was no clear minority view, a number of respondents recommended eliminating R2 or R4 because of practical difficulties associated with the CCZ and their belief that R5, R6, and R7 were sufficient to achieve reliability

In response, the SDT modified R2 so that it does not use the CCZ to trigger the imminent threat procedure implementation. R2 now requires the Transmission Owner to implement its imminent threat procedure when it has knowledge of such a threat obtained through normal operating procedures. The SDT decided not to be prescriptive in the definition of a vegetation imminent threat. Rather, the Transmission Owner should have the flexibility of defining its own procedure per the TVMP. In addition R4 has been modified and now requires the Transmission Owner to prevent vegetation encroachment of the Minimum Vegetation Clearance Distances (MVCD) as observed in real time and eliminates the use of the CCZ for this purpose.

R2. Each Transmission Owner shall implement its imminent threat procedure when the Transmission Owner has actual knowledge of such a threat, obtained through normal operating practices.

Deleted: or notification from others, that the Critical Clearance Zone is approached by vegetation to prevent an encroachment of the Critical Clearance Zone.

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Organization	Agree?	Question 11 Comment
BCTC		BCTC feels that changing to the Gallet equation will not have a large impact on its vegetation management operations, so we have no concerns. We agree with R2, but feel that this clause makes R4 redundant, as per our discussion under Comment # 15 below. We recommend the removal of R4 entirely from the standard.

Organization	Agree?	Question 11 Comment
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Western Utility Arborists		The Western Utilities feel that changing to the Gallet equation will not have a large impact on its vegetation management operations, so we have no concerns. We agree with R2, but feel that this clause makes R4 redundant, as per our discussion under Comment # 15 below. We recommend the removal of R4 entirely from the standard.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Associated Electric Cooperative Inc.	Disagree	The phrase “Critical Clearance Zone is approached” in R2 is nebulous and probably unenforceable. The determination and visualization of the Critical Clearance Zone and approaching vegetation encroachment, under field conditions, is a practice in application of theoretical conductor locations in real time. Would the Transmission Owner be found in noncompliance if evidence showed vegetation had “approached” within 20 feet, 2 feet, 2 inches or some other arbitrary distance of the CCZ and the TO failed to implement its imminent threat procedure?
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Western Area Power Administration, Upper Great Plains Region	Disagree	The CCZ as defined would very specifically outline a zone that needs to remain clear of vegetation to avoid a violation, but that specificity could be an overly burdensome concept to implement and/or monitor. Theoretically, there could be an infinite number of allowable vertical and horizontal (for outside phases) clearances depending on your location within each span. Theoretically, you may need to clear cut at mid-span (depending on retreatment intervals, growth rate, etc.) while allowing a 40 foot tree closer to the structure, along with everything in between depending on your location within the span. To fully comply with the CCZ as defined, each Transmission Owner would have to have a table of allowable vertical and horizontal clearances for every few feet on every available span length within each line section. Producing such tables

Organization	Agree?	Question 11 Comment
		would be a significant burden to each Transmission Owner, but without them, the Transmission Owner could not verify that vegetation had not encroached within the CCZ. In order to produce the tables outlined above, the Transmission Owner would need to identify what design parameter(s) are applicable for the "correct" CCZ? We remain concerned that weather conditions in excess of those parameters could lead to a vegetation contact/outage and proving that weather conditions were in excess of design criteria would be extremely difficult or impossible for all spans on a lengthy transmission line. It is not uncommon to have weather stations 50 or more miles away from points on our transmission system. In order to certify/verify compliance, the Transmission Owner would have to physically take their table to the field and verify vertical and horizontal clearances from the edge of the theoretical envelope (not the actual conductor position) for all vegetation within the span. This would be a time-consuming, burdensome, cumbersome process if Regulators are going to require specific evidence in order for the Transmission Owner to document their annual certification.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
SERC Vegetation Management Subcommittee (VMS)	Disagree	The SERC VMS recommends that R2 be deleted. Since this is a "zero tolerance" standard any Transmission Owner will remove any discovered threats to prevent outages. While we agree that the implementation of an imminent threat procedure may be a valid concept, visualization of the Critical Clearance Zone (CCZ) and determining an approaching encroachment is a practice in application of theoretical conductor locations in real time.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Progress Energy Florida	Disagree	The Critical Clearance Zone as currently defined is too academic. Implementation of R2 would require field operations staff to determine the theoretical position of the line during inspections to decide whether to engage the imminent threat procedures. The academic/theoretical aspects of the Critical Clearance Zone definition are not practical or enforceable. The criteria for a violation needs to be limited to the position of the conductor in real time.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		

Organization	Agree?	Question 11 Comment
Western Area Power Administration, Rocky Mountain Region	Disagree	As discussed in the Technical Reference document, the CCZ is a complicated theoretical envelope surrounding all rated operating positions of the conductor. Its dynamic shape is constantly changing and is contingent upon location within the span. Calculation of the size and shape of CCZ is based, in part, upon the design parameters of the transmission facility. However, as-built or long term maintenance conditions can often diverge from the original design requirements over time. Ground elevations can also change as a result of man made or natural causes from the original design elevations recorded on plan and profile engineering drawings. Consequently, precise field measurement of the as-built CCZ is extremely problematic and strategies that utilize the calculation of allowable right-of-way tree heights can be hindered by unrecorded deviations from the original design criteria. Allowable tree height strategies also become increasingly more difficult and impractical with increasing extremes in terrain. While the CCZ is a very important concept for an effective vegetation management program it is far to theoretical, dynamic, and impractical to field measure for use as a clear and precise boundary for regulatory purposes. In addition, the R2 requirement for action when the imprecise and theoretical CCZ boundary is "approached" by vegetation is an even more subjective and unmeasurable. The "rate of approach" is really the key issue of concern. The rate of vegetation approach is a function of many variables including species type and site specific growing conditions. For example, a Century Plant which can grow six inches a day is obviously a much greater concern than a Lodgepole Pine on a dry mountain top which grows only a few inches a year. As such, there is no practical way to define or measure for regulatory purposes those "approach" situations that legitimately require immediate action from those "approach" situations that do not. The wording and concepts of R2 are therefore to imprecise to be used as clear requirements for Standards compliance.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Progress Energy Carolinas	Disagree	The Critical Clearance Zone as currently defined is too academic. Implementation of R2 would require field operations staff to determine the theoretical position of the line during inspections to decide whether to engage the imminent threat procedures. The academic/theoretical aspects of the Critical Clearance Zone definition are not practical or enforceable. The criteria for a violation needs to be limited to the position of the conductor in real time.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
SERC OC Standards Review	Disagree	The SERC OCSRG recommends that R2 be deleted. Since this is a "zero tolerance" standard any

Organization	Agree?	Question 11 Comment
Group		Transmission Owner will remove any discovered threats to prevent outages. While we agree that the implementation of an imminent threat procedure may be a valid concept, visualization of the Critical Clearance Zone and determining an approaching encroachment is a practice in application of theoretical conductor locations in real time.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Florida Power & Light	Disagree	FPL agrees that the Gallet equation is a better method to determine a Critical Clearance Zone. However, FPL does not agree with the application of the zone for several reasons outlined below. ? There are many environmental and engineering variables and assumptions included in the calculation of the Critical Clearance Zone. ? These assumptions are not clearly defined in the standard. ? Unless there is a significant intrusion into the Critical Clearance Zone, an engineer and surveyor would be necessary at all times to determine a violation. ? The success of this standard lies with a standard the field personnel can implement. When making actual trimming or removal decisions, the field personnel are not adequately skilled to do much more than make a rough guess at the Critical Clearance Zone. This standard must establish measurable and auditable parameters for field operations. ? In Requirement R2, determination of when to activate the Imminent Threat Procedure becomes unclear due to the difficulty in determining when the Critical Clearance Zone is encroached. ? As written, off ROW trees falling through the Critical Clearance Zone become a violation of Requirement R4. Unless an outage occurred, how would the utility determine that a violation occurred? In FAC 003-1 an outage of this nature is defined as Category 3 and is not a violation. Since fall-in tree interruptions have never been contributors to cascading events or blackouts they should not be a violation of a NERC standard. Consequently, as written, it is highly questionable whether this Standard is sufficiently specific and clear to be enforceable. The many questions and levels of confusion introduced with the application of the Critical Clearance Zone concept suggests that neither the industry nor NERC will ever know if compliance is met. Such a high level of ambiguity requires that the Critical Clearance Zone concept be revisited and most likely replaced with a measure that is workable for both the industry and NERC. To further this effort, FPL has outlined some alternative suggestions described in the answer to question 18.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		

Organization	Agree?	Question 11 Comment
Southern Company	Disagree	As written, R2 requires activation of the imminent threat process when the Critical Clearance Zone (CCZ) is "approached" by vegetation. The term "approach" is vague and open to interpretation. Since vegetation is dynamic in nature, it is constantly "approaching" any pre-defined zone. There could also be many examples given of encroachments into the theoretical CCZ that would neither threaten the transmission line conductor nor cause a reduction in the capacity of the transmission line. This concept would be better suited to be a “trigger point” that, if found, would be incentive for the Transmission Owner to take immediate action or ensure future action occurs on schedule. This action may be as urgent as implementation of the immediate threat procedure or as non-urgent as making sure that the upcoming maintenance on that line is scheduled appropriately. We are concerned this revision of FAC-003 continues to take a zero tolerance approach to compliance, which is contrary to the philosophy utilized in other NERC standards. A state of non-compliance should not exist simply because vegetation encroached within a pre-defined zone by a fractional inch, but only when an event, such as a sustained outage, occurs due to the Transmission Owner's failure to maintain adequate clearance between conductors and vegetation.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
E.ON U.S.	Disagree	E.ON U.S. suggests that R2 be deleted. Since this is a "zero tolerance" standard any Transmission Owner will remove any discovered threats to prevent outages. While we agree that the implementation of an imminent threat procedure may be a valid concept, visualization of the Critical Clearance Zone and determining an approaching encroachment is a practice in application of theoretical conductor locations in real time.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
FirstEnergy	Disagree	The CCZ is not equal to Clearance 2 in FAC-003-1. Per requirement R4, any encroachment into the CCZ is a violation of the standard even if an outage does not occur. This is too strict because it refers to a "0" tolerance even for encroachments that do not affect reliability. This can be an extremely costly standard to comply with that may or may not improve reliability. The CCZ distance is a difficult to determine from one moment to the next based upon the description and calculations outlined. The conditions on the right of way are dynamic and ever changing. It would be more proactive for the TO to focus on implementing the TVMP rather than expending time and money trying to determine if the CCZ has been violated. A better approach

Organization	Agree?	Question 11 Comment
		would be to establish a minimum clearance at all times rather than to monitor encroachment to a theoretical CCZ.
Response: Thank you for your comment. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Midwest ISO Stakeholders Standards Collaborators	Disagree	he CCZ is a good theoretical concept to aid industry in understanding the overall movement of conductors, but it is an impractical concept for field application. Due to the variability in the size of the CCZ as you move along a conductor, as well as changes from span to span or even line to line due to design parameters, loading or weather-related issues, the CCZ concept should not be tied to an imminent threat procedure. Vegetation approaching the CCZ does not constitute an imminent threat. It may be months to years before this vegetation ever gets to a proximity distance from the conductor to be within a "spark-over" distance as defined by the Gallet equations. Requirement R2 should support the purpose of this standard by requiring implementation of the Vegetation Imminent Threat Procedure when the Transmission Owner has visual, field knowledge that vegetation is encroaching upon a conductor within some specific distance that is a multiple of the Gallet distances referenced in Table I of FAC-003-2 (to be conservative we suggest two to three times the Gallet distances). Failure to implement the Vegetation Imminent Threat Procedure in such instances would be a violation of R2.As R2 is currently stated, a Transmission Owner cannot comply with R2 unless the imminent threat procedure is continuously being implemented, because vegetation that is growing is always approaching the CCZ. "Approaching the CCZ" cannot be the trigger for implementation of the Vegetation Imminent threat Procedure. Instead, the trigger should be an encroachment within some observed field distance. Requirement R2 could be reworded as follows: ?Each Transmission Owner shall implement its Vegetation Imminent Threat Procedure when the Transmission Owner has knowledge, obtained through normal operating practices or notification from others, that vegetation is encroaching upon a conductor within a distance that is twice the Gallet clearance distances referenced in Table I." Using a multiple of the Gallet distances provides a safety factor. Assessing a violation for failure to appropriately implement the Vegetation Imminent Threat Procedure or for a sustained vegetation-related outage incents the proper behavior.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4. The proposed standard revision specifies the MVCD as a starting point and TOs may apply multiples at its own discretion in order to achieve its TVMP objectives and adhere to applicable safety standards.		

Organization	Agree?	Question 11 Comment
SERC Compliance Staff	Disagree	SERC staff agrees that the implementation of an imminent threat procedure may be a valid concept; however visualization of the Critical Clearance Zone and determining an approaching encroachment will be difficult from a practical matter. There also needs to be definition of what is meant by "approaching" if this is used. While it may be a technically sound approach to designate the clearance zone to be tied to the conductor movement envelope as found in the NESC, this results in a banana-shaped zone that is difficult to substantiate in the field by entity and compliance personnel. It may be better, and more reasonable to define a constant zone around a conductor that would be the same throughout the span. The clearance zone should not include the limitation that the zone cannot extend outside the active right of way.
Response: Thank you for your comment. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
ITC HOLDINGS	Disagree	Just because vegetation is approaching the CCZ doesn't represent an imminent threat and should not be set to an imminent threat procedure. Implementation of R2 would require field personnel to determine the speculative position of the line during inspections to decide whether to engage the imminent threat procedures. While we agree that an imminent threat procedure should be implemented to address vegetation related imminent threats as soon as they are identified, we believe that an approach of the CCZ should not be used to generate implementation. The term "approached" does not identify a specific distance, so it's not clear to what extend vegetation would have to approach the CCZ to require implementation of the imminent threat process. ITC agrees that the implementation of an imminent threat procedure may be a valid concept, but visualization of the CCZ and determining approaching vegetation is a practice in hypothetical conductor locations in real time. This may be a good imaginary concept in understanding conductor movement but it's impractical for field applications.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Tennessee Valley Authority	Disagree	TVA recommends that R2 be removed from this standard. Since this is a "zero tolerance" standard there is a very significant incentive for the Transmission Owner to inspect and plan maintenance to prevent potential outages. The Gallet Equations should be kept within the white paper solely for the TO to reference for developing maintenance and inspection cycles.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has		

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discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Exelon	Disagree	Comments: 1) In spite of the rigor associated with the Gallet equations, the definition of CCZ is imprecise as the Ratings to be used are not specified. In addition, Exelon is concerned that it will be difficult to determine the CCZ for each span under all possible operating conditions. Implementing an imminent threat procedure (R2) in combination with the CCZ may be unworkable under actual field conditions. 2) We are concerned that CCZ is only fully defined in the Technical Reference documentation and not in the standard itself. As stated in the NERC Standards Process Manual, Elements of a Reliability Standard, "Supporting documents to aid in the implementation of a standard may be referenced by the standard but are not part of the standard itself." There needs to be enough specificity as to the definition of CCZ in FAC-003-2 so that adequate documentation and evidence of compliance can be developed.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
American Electric Power (AEP)	Disagree	AEP agrees with the need for a TO to have an Imminent Threat Procedure and that the Transmission Operator should be immediately notified of imminent threats. However, AEP disagrees with the requirement that the Transmission Operator be notified merely because the CCZ has been approached. Vegetation approaching the CCZ does not necessarily constitute an imminent threat. It is possible that the CCZ is encroached by vegetation at the lowest point of the CCZ whereas the conductor may be at its highest point in the CCZ (potentially 20 or 30 feet away from the vegetation). This situation does not merit notification to the Transmission Operator. Please also refer to our comments regarding CCZ in AEP's responses to Questions 15 and 18.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		

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Platte River Power Authority	Disagree	Changing to the Gallet equation will not have a large impact on vegetation management operations, keeping Clearance 1 and 2 with tables developed using IEEE Standards for various voltages, line spans and altitudes is preferable. Actions should be taken to prevent an outage when vegetation encroaches Clearance 2.
Response: Thank you for your comment. The SDT chose to use Gallet equations over IEEE primarily because Gallet is more appropriate for determining the probability of flashover. The IEEE standard was developed for human safety purposes.		
Northern Indiana Public Service Company	Disagree	While I agree with the argument that the Gallet equatiion is a better technical or scientific method than IEEE 516 for determining realistic conductor to tree flashover distances, I do not agree that the new proposed clearance tables serve any useful purpose as a vegetation clearance standard from an operational perspective. The FAC-003-2 Technical Reference itself points to this fact when it states, "even if the exact size and shape of the C.C.Z. is known, it becomes nearly impossible in the field to correlate and accurately superimpose the C.C.Z. around the conductor." The Tech. Ref. goes on to say that "it is anticipated that many T.O.s will establish a work trigger well outside the C.C.Z." I agree wholeheartedly with that concept and believe that the Gallet clearance tables should be used by TO's to develop the more important "work trigger" or "action threshold" clearances. This revision is overly focused on C.C.A.'s that have no practical operational application while being silent to the more critical to reliability issue of "work trigger/action threshold" clearances. This needs to be addressed if we hope to be successful at achieving the goal of zero preventable tree related outages.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Tampa Electric Company	Disagree	This is a good start. The Critical Clearance Zone (CCZ) is a very real and practical concept; however, it is not transferable to field conditions. This could result in a "fill in the blank" standard relative to what the Critical Clearance Zone will be in terms of distance. As I read this, it will be a sliding scale from insulator to mid span and back for each designated line voltage. The max wind speed to be used and other assumptions behind the determination of this zone may be as involved a Gallet's formula. This will lead to complications during operational inspection and verification of these clearances.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission		

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Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Orange and Rockland Utilities Inc.	Disagree	While we agree that the imminent threat procedure should be implemented to address vegetation-related imminent threats as soon as they are identified, we believe that an "approach" of the CCZ should not be used to trigger implementation. The term "approached" does not identify a specific distance, so it is not clear to what extent vegetation would have to approach the CCZ in order to require implementation of the imminent threat process. This is left to the discretion of individual interpretation, is confusing to field personnel, and presents compliance and auditing problems. Imminent threats which are based on vegetation clearances should be identified based on specific clearances, not undefined approach distances. In practical field application the CCZ is an invisible area that changes shape and size along the length of the conductor. It is impossible to readily identify in the field without engineering calculations and precise measurements or the use of technology such as Aerial Laser Survey (ALS) using Light, Detection and Ranging (LIDAR) technology. Therefore under normal circumstances the location, size, and shape of the CCZ and vegetation encroachments of the CCZ can only be roughly estimated. Even with the use of ALS, which is relatively accurate, information is often not available for months after the survey flight. We believe that under normal circumstances imminent threats which are based on vegetation clearances should be identified in terms of specific distances from the conductor. While it is not possible for an inspector to readily identify a vegetation encroachment of the CCZ in the field, an inspector could more easily estimate a specified short distance between a conductor and vegetation in real time and initiate implementation of the imminent threat procedure based on that assessment. This assessment would be significantly more accurate than attempting to measure the distance between vegetation and the CCZ, which is not visible and constantly changes size and shape throughout the span. In cases where the Transmission Owner chooses to deploy ALS, the CCZ rather than the conductor could be used as the reference because in most cases the CCZ could be identified relative to approaching vegetation with a reliable degree of accuracy. Still a specific distance should be used to trigger implementation of the imminent threat procedure because of the issues previously raised with the use of the word "approached".
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
American Transmission Company	Disagree	ATC believes that the Critical Clearance Zone (CCZ) is a good theoretical concept to aid industry in understanding the overall movement of conductors, but it is an impractical concept for field application. Due to the variability in the size of the CCZ as you move along a conductor, as well as changes from span to span or

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		even line to line due to design parameters, loading or weather-related issues, the CCZ concept should not be tied to an imminent threat procedure. Vegetation approaching the CCZ does not constitute an imminent threat. It may be months to years before this vegetation ever gets to a proximity distance from the conductor to be within a "spark-over" distance as defined by the Gallet equations. Requirement R2 should support the purpose of this standard by requiring implementation of the Vegetation Imminent Threat Procedure when the Transmission Owner has visual, field knowledge that vegetation is encroaching upon a conductor within some specific distance that is a multiple of the Gallet distances referenced in Table I of FAC-003-2 (to be conservative we suggest two to three times the Gallet distances). Failure to implement the Vegetation Imminent Threat Procedure in such instances would be a violation of R2.As R2 is currently written, a Transmission Owner cannot comply with R2 unless the imminent threat procedure is continuously being implemented or monitored, because vegetation that is growing is always approaching the CCZ. "Approaching the CCZ" cannot be the trigger for implementation of the Vegetation Imminent threat Procedure. Instead, the trigger should be an encroachment within some observed field distance. Requirement R2 could be rewritten as follows: ?Each Transmission Owner shall implement its Vegetation Imminent Threat Procedure when the Transmission Owner has knowledge, obtained through normal operating practices or notification from others, that vegetation is encroaching upon a conductor within a distance that is twice the Gallet clearance distances referenced in Table I." Using a multiple of the Gallet distances provides a safety factor. Assessing a violation for failure to appropriately implement the Vegetation Imminent Threat Procedure or for a sustained vegetation-related outage would promote the proper behavior.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4. The proposed standard revision specifies the MVCD as a starting point and TOs may apply multiples at its own discretion in order to achieve its TVMP objectives and adhere to applicable safety standards.		
Ameren	Disagree	The CCZ is a good theoretical concept to aid industry in understanding the overall movement of conductors, but it is an impractical concept for field application. Due to the variability in the size of the CCZ as you move along a conductor, as well as changes from span to span or even line to line due to design parameters, loading or weather-related issues, the CCZ concept should not be tied to an imminent threat procedure. Vegetation "approaching" the CCZ does not constitute an imminent threat. In fact, the moment after vegetation is cut, it begins again to "approach" this zone. It may be months to years before this vegetation ever gets to a proximity distance from the conductor to be within a "spark-over" distance as defined by the Gallet equations. Requirement R2 should support the purpose of this standard by requiring implementation of the Vegetation Imminent Threat Procedure when the Transmission Owner has visual, field knowledge that vegetation is encroaching upon a conductor within some specific distance. As R2 is currently stated, a

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		Transmission Owner cannot comply with R2 unless the imminent threat procedure is continuously being implemented, because vegetation that is growing is always approaching the CCZ. "Approaching the CCZ" cannot be the trigger for implementation of the Vegetation Imminent threat Procedure. Instead, the trigger should be an encroachment within some observed field distance.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Nebraska Public Power District	Disagree	The CCZ is a good concept to explain the flight path of a conductor under all conditions but it would be impractical to use in the field. There are too many variables to consider and an encroachment does not constitute an immediate threat.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Manitoba Hydro	Disagree	The imminent threat process trigger should be well defined, and the vague "approaching" terminology needs to be changed. Imminent threat implies and that an elevated risk of contact exists. That is not the case if the vegetation is merely approaching the CCZ. The objective of the overall Vegetation Management program is to prevent an encroachment. The imminent threat procedure should be triggered by discovery of an encroachment into the CCZ. Even when an actual encroachment into the CCZ occurs - while the odds of an outage event have increased - the likelihood of a contact is still minimal, as other environmental factors still need to be in place (i.e. high temperature and/or high wind conditions).If this approach to an imminent threat process trigger, then the violation of this requirement implies a violation of R4, which prohibits the encroachment of the CCZ, and therefore either R2 or R4 could be removed, or they could be combined into one requirement.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. The Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Consumers Energy Company	Disagree	Absolutely disagree! The Gallet formula distances do not provide adequate protection of the system. The "Critical Clearance Zone" concept is not workable in the field. Every foot of every span would have a different

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		CCZ that cannot be measured in the field without survey type equipment and knowledge of current line loadings. The clearance requirement needs to be uniform along the span for field crews to effectively achieve compliance. It appears that the drafting team hopes to minimize violations of vegetation violating FAC-003-1 Clearance 2 distances by decreasing the clearance distance between the conductor and vegetation using the Gallet formula. If NERC believes that FAC-003-1 Clearance 2 distances are too conservative, then the Gallet formula distance needs to be increased by some multiplier (2 or3) to achieve adequate safeguard for growing vegetation. Most trees in the United States in the size range that could exist beneath conductors achieve height growth of 3 feet or more annually. A tree in May may have adequate clearance per the proposed CCZ and in July violate that clearance causing an outage. Therefore, if the CCZ is to remain as is then the transmission owner/operator must have a defined imminent threat distance considerably greater than the CCZ and must be great enough that field personnel can safely remove the threat without de-energizing or de-rating the line.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4. The proposed standard revision specifies the MVCD as a starting point and TOs may apply multiples at its own discretion in order to achieve its TVMP objectives and adhere to applicable safety standards.		
Pacific Gas & Electric Co.	Disagree	PG&E agrees the Gallet equation is superior to IEEE 516 and the imminent threat procedure is a critical component of the standard but disagrees that initiation of the procedure be based on such ambiguous language as "approaching the CCZ". Approaching could be any and all vegetation that is live and growing and CCZ is a theoretical calculation not a real time event. As written, the standard would require the TO to initiate an emergency action when such action may not be warranted or necessary to prevent an outage. PG&E recommends using a clearly defined and measureable threshold to determine when the imminent threat procedure must be initiated. A reasonable threshold would be 3 times the Gallet clearance distances referred to in Table 1 or when vegetation is threatening to fall into or otherwise impact a line.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4. The proposed standard revision specifies the MVCD as a starting point and TOs may apply multiples at its own discretion in order to achieve its TVMP objectives.		

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San Diego Gas & Electric	Disagree	We do not agree with replacing Clearance Zone 2 with the Critical Clearance Zone. We recommend the removal of R4 entirely from the standard.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Consolidated Edison Company of New York (CECONY)	Disagree	CECONY is in favor of using the Gallet equations as they provide a more realistic clearance distance for vegetation. We understand and agree that establishing a Critical Clearance Zone (CCZ) would provide the specific area that a conductor could possibly travel through during various field and weather conditions but we do not agree that this is the most practical approach. The main issue is that the wording '...the Critical Clearance Zone is approached by vegetation.....' is very vague and left open to wide interpretation which causes inconsistency and confusion throughout the industry. The CCZ changes throughout the length of each conductor in each span so a field inspector's job and an auditor's job become much more complicated when trying to confirm compliance when vegetation is present in the Actiove ROW. We feel that the time spent trying to measure and calculate the CCZ and then confirm compliance would be better spent initiating a response plan to safely remove the vegetation. The imminent threat procedure would only be implemented if vegetation encroaches beyond a specific distance from the conductor, not as it approaches the theoretical CCZ. Advanced technology would be required if a vegetation approach distance to the CCZ was to be calculated in the field. This is a very costly and time consuming requirement and does not efficiently meet the Standard's goal of ensuring reliability.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Duke Energy Corporation	Disagree	No. Duke believes that the CCZ is a good theoretical concept to aid industry in understanding the overall movement of conductors, but it is an impractical concept for field application. Due to the variability in the size of the CCZ as you move along a conductor, as well as changes from span to span or even line to line due to design parameters, loading or weather-related issues, the CCZ concept should not be tied to an imminent threat procedure. Vegetation approaching the CCZ does not constitute an imminent threat. It may be years before this vegetation ever gets to a proximity distance from the conductor to be within a "spark-over" distance

Organization	Agree?	Question 11 Comment
		as defined by the Gallet equations. Requirement R2 should support the purpose of this standard by requiring implementation of the Vegetation Imminent Threat Procedure when the Transmission Owner has visual, field knowledge that vegetation is encroaching upon a conductor within some specific distance that is a multiple of the Gallet distances referenced in Table I of FAC-003-2 (to be conservative we suggest two times the Gallet distances). Failure to implement the Vegetation Imminent Threat Procedure in such instances would be a violation of R2.As R2 is currently stated, a Transmission Owner cannot comply with R2 unless the imminent threat procedure is continuously being implemented, because vegetation that is growing is always approaching the CCZ. "Approaching the CCZ" cannot be the trigger for implementation of the Vegetation Imminent threat Procedure. Instead, the trigger should be an encroachment within an observed distance from vegetation to conductor that is twice the Gallet distances in Table I. Requirement R2 could be reworded as follows: ?Each Transmission Owner shall implement its Vegetation Imminent Threat Procedure when the Transmission Owner has knowledge, obtained through normal operating practices or notification from others, that vegetation is encroaching upon a conductor within a distance that is twice the Gallet clearance distances referenced in Table I." Using a multiple of the Gallet distances provides a safety factor. Assessing a violation for failure to appropriately implement the Vegetation Imminent Threat Procedure or for a sustained vegetation-related outage incents the proper behavior.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4. **The proposed standard revision specifies the MVCD as a starting point and TOs may apply multiples at its own discretion in order to achieve its TVMP objectives and adhere to applicable safety standards.**		
Entergy Services	Disagree	: 1. Entergy suggests that the requirement for activation of the vegetation imminent threat process should not be tied to the Critical Clearance Zone and that the each entity should define the activation of their vegetation imminent threat process. Tying the activation of the imminent threat process to the Critical Clearance Zone is limited in that this criterion does not address the possibilities of vegetation falling into the line or Critical Clearance Zone. 2. In the sentence “Critical Clearance Zone approached by vegetation” the use of “approached” is subjective and not specifically quantifiable. Effective, uniform activation of the imminent threat process will require objective measurement criteria. 3. The standard needs to include a clear statement to the effect that when the Transmission Operator is notified of a potential vegetation problem, obtained by normal operations and inspections, the entity will

Organization	Agree?	Question 11 Comment
		activate the Vegetation Imminent Threat Process. 4) This requirement, as stated, is redundant. The requirements for maintaining the Critical Clearance Zones and / or avoiding vegetation outages, and the associated Violation Risk Factors and Violation Severity Levels, already reinforce the desired behavior of the entity to identify and mitigate any potential issues before the possibility of vegetation causing an outage.
Response: Thank you for your comment. **1) The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4. These changes may address your concerns.** **2) Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The word, "approached" is not used in the revised standard.** **3) Requirement R1 Part 1.4 specifies the TVMP have an Imminent Threat procedure that includes notification of the responsible control center.** **4) The SDT believes that having to implement an Imminent Threat procedure is proactive behavior and is in support of prevention of outages.**		
Pepco Holdings, Inc	Disagree	R5, R6 and R7 make this requirement redundant and unnecessary - it should be deleted. It is largely unenforceable and does not make the standard clear, specific and regulatory enforceable. Further, PHI believes the concept of enforcing no encroachment into the Critical Clearance Zone is a flawed approach.
Response: Thank you for your comment. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4. **The SDT believes that having to implement an Imminent Threat procedure is proactive behavior and is in support of prevention of outages.**		
JEA	Disagree	The use of Gallet equations is not practical either for field use or for demonstrating compliance.
Response: Thank you for your comment. The SDT chose to use Gallet equations over IEEE primarily because Gallet is more appropriate for determining the probability of flashover and the SDT believes holds distinct advantages for use in vegetation management applications. IEEE 516 is developed for human safety purposes.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	We feel that changing to the Gallet equation will not have a large impact on its vegetation management operations, so we have no concerns. We agree with R2, but feel that this clause makes R4 redundant, as per

Organization	Agree?	Question 11 Comment
		our discussion under Comment # 15 below. We recommend the removal of R4 entirely from the standard.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
WECC	Agree	Yes but the wording is ambiguous. Vegetation under a transmission line is always "approaching" or growing towards the transmission line. Entities should define a specific distance greater than the Critical Clearance Zone when they are required to implement their Imminent Threat Procedures.
Response: Thank you for your comment. The proposed standard revision specifies a "Minimum Vegetation Clearance Distance" as a starting point and TOs may apply greater distances at their discretion in order to trigger implementation of the Imminent Threat procedure. The word, "approaching" is not used in the revised standard.		
Baltimore Gas & Electric Company	Agree	Again, each utility is responsible and accountable for it's actions. The Gallet clearances are a much better approximation of a true spark gap than the present requirement. Without a clearance one requirement, the closer tolerance produced by the Gallet equation will leave little room for error when a line is at or approaching it's max. engineered sag. When vegetation gets in the new CCZ (if adopted), it will be likely that an outage will be imminent. With the present clearance 1 and clearance 2 requirements, there is more of a buffer for encroaching vegetation.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4. **The proposed standard revision specifies the MVCD as a starting point and TOs may apply multiples at its own discretion in order to achieve its TVMP objectives and adhere to applicable safety standards.**		
CenterPoint Energy	Agree	We agree with replacing IEEE 516 standard distances with the Gallet equation standard distances. However, the term "Critical Clearance Zone" refers to the "limits of the Active Transmission Line Right-of-way" which has no specific definition as to its limits within the proposed revised Standard. (See comments to Q3 above.) R2 should be reworded to coordinate with R1.4. (See comments to Q4 above.)

Organization	Agree?	Question 11 Comment
Response: Thank you for your comments. Please see our responses to Questions 3 and 4 comments as well as the summary consideration for this question Based on stakeholder comments, the SDT made significant modifications to Requirement R2 and removed the concept of the CCZ.		
Salt River Project	Agree	Although we agree that using the Gallet equation is more definitive than using IEEE 516, we still question from an engineering prespective as to how and why this method was chosen. It is stated in the Technical Reference paper that the Gallet Equation is a well known method of computing the required strike distance for proper insulation coordination. It is our understanding it's purpose is for designing towers, to define the "tower window" or opening inside of a tower under normal conditions. Because this is not a method designed specifically for vegetation management, was there any physical testing involved in choosing this approach, such as testing in both wet and dry conditions? We would recommend additional information to clarify this method to use for vegetation management. See additional comments in Comment #18 below. In addition, we feel this clause makes R4 redundant, as per our comments under Comment #15 below.
Response: Thank you for your comment. The Gallet equations indeed are useful in tower design; however it is not exclusively for that purpose. The decision whether to use Gallet is not contingent upon testing and none were considered or conducted. No physical testing was utilized by the SDT; however, the Gallet Equation method and its explanation in the White Paper do have their basis in physical testing in both laboratory and field conditions. The Gallet Equation method is not solely applicable to tower structure design, but to any application requiring spark-over calculations. The SDT believes that the Gallet Equation method holds distinct advantages over the IEEE 516 method for use in vegetation management applications.		
Southern California Edison Company	Agree	Q11: SCE agrees in part with proposed R2. The use of the Gallet equation and the replacement of the existing Clearance 2 requirement with the Critical Clearance Zone is acceptable. However, SCE strongly disagrees with establishing a separate requirement for implementing an imminent threat procedure should there be an encroachment of the Critical Clearance Zone because it forms the basis of an unnecessary zero-tolerance enforcement policy. Read in context with corresponding Measure 2, R2 appears to require Transmission Owners to prove that a Critical Clearance Zone encroachment did or did not occur and also prove that that an imminent threat procedure was or was not properly invoked. Although SCE agrees that CCZ encroachments should be addressed timely, we disagree with the notion and underlying assumption that a CCZ incursion will always lead to a flash-over or a vegetation-to-line contact. If the goal of FAC-003-2 is to prevent sustained outages (due to vegetation-to-line contacts) that could lead to Cascading, emphasizing “prevention” is understandable, however, enforcing prevention measures is an entirely different matter. Under the proposed requirements, a vegetation-to-line contact could conceivably represent two distinct violations of FAC-003-2. SCE believes this type of regulatory double jeopardy is patently unfair and forcing Transmission Owners to prove a CCZ encroachment did or did not occur is equally unfair and unenforceable. Because R1.4 adequately addresses the Transmission Owner’s responsibility regarding the implementation of an imminent threat procedure, SCE respectfully recommends that proposed R2 and corresponding M2 be removed from

Organization	Agree?	Question 11 Comment
		FAC-003-2.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Buckeye Power, Inc.	Agree	I agree with R2. I like the language changes, but decreasing the clearances will not improve reliability.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Great River Energy	Agree	GRE agrees and believes that the Gallet equation yields a less subjective measurement. GRE believes R2 should be modified to be more definitive. The imminent threat procedure should be implemented when vegetation “enters” the Critical Clearance Zone (CCZ). It is GRE's opinion that approaching the CCZ is subjective and as such very difficult to enforce.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	Attachment 1 is very conservative. I think that the clearance distances shown on the attachment should be expanded to create, in effect, a standard that reflects maximum line loading and maximum line sag. I would also like to see some flexibility built into the process so that the Transmission Owner and the USFS could negotiate some consideration for vegetation growth rates. The end result would generate a standard that would give the Transmission Owner the security of knowing that vegetation would not grow into the potential arcing zone for some reasonable amount of time - some kind of entry cycle.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT		

Organization	Agree?	Question 11 Comment
modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Measure M2 requires that the entity have evidence showing dates and activities accomplished to meet the R2 implementation requirement. The SDT notes that the proposed standard revision does not preclude the USFS and the TO from negotiating consideration for vegetation growth rates and in fact it is a good idea.		
City of Tallahassee	Agree	As long as we do not have to have evidence of using the calculation! We should be able to use Table I as provided.
Response: Thank you for your comment. Please see the summary response. Many commenters disagreed with this requirement and it has been substantially modified.		
Bonneville Power Administration	Agree	BPA agrees with R2, but refer to comments submitted regarding R4 (please see our response to Question #15) for related recommendations to R2.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
MRO NERC Standards Review Subcommittee	Agree	The MRO agrees and believes that the Gallet equation yields a less subjective measurement. The MRO believes R2 should be modified to be more definitive. The imminent threat procedure should be implemented when vegetation “enters” the critical clear zone. Fines and violations for approaching the zone is not measurable or enforceable. The MRO believes that "approached" is subjective and not enforceable and should be removed from the requirement.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Northern California Power Agency (NCPA)	Agree	
Santee Cooper	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	

Organization	Agree?	Question 11 Comment
Arizona Public Service Company	Agree	
Independent Electricity System Operator	Agree	
Northeast Utilities	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
NPCC	Agree	
WECC Reliability Coordination	Agree	
Kansas City Power & Light	Agree	
National Grid	Agree	
Long Island power Authority	Agree	
Central Maine Power Company		No comment

12. The Standard Drafting Team revised the spark-over (also referred to as "flashover") distance thresholds utilizing technically-equivalent Gallet equations in lieu of IEEE 516 minimum air insulation distance (MAID) calculations that were used in FAC-003-1. The rationale is that the minimum air insulation distances in IEEE 516 were safety clearances developed under laboratory conditions and thus there exists concern these distances may be too conservative to apply to lines operating in actual field conditions. Do you agree with this? If not, please explain.

Summary Consideration: The majority of responders (90%) agreed with this change. The minority view favored the continued use of IEEE 516 and four responders advocating removing the tables from the standard.

After reviewing the industry comments, the SDT continues to support the merits of using the Gallet equations and maintaining the tables in the standard. IEEE 516 values are safety clearances developed under laboratory conditions and thus these distances are inappropriate for vegetation spark-over clearances associated with lines operating in actual field conditions. In addition, IEEE Standards are subject to change which the SDT did not desire to have the Vegetation Reliability associated with an IEEE Standard that may change without proper consideration of the impact to the Vegetation Reliability Standard.

By using the Gallet distances, the SDT feels this is a technically sound, independent value that represents a true spark-over threshold distance. One must remember this is a minimum distance and the new requirement of 1.6 specifies the Transmission Owner develop a maintenance strategy to ensure these clearances are never violated.

Organization	Question 12	Question 12 Comment
SERC Compliance Staff	Disagree	While the actual sparkover distance may be more correctly calculated using the Gallet equations, SERC staff believes it is a less conservative approach to the goal of preventing vegetation related outages. If the concept of the CCZ will remain in the standard, we suggest that the tables based on the Gallet equations be removed from the standard and be kept in the technical white paper solely to assist in developing a common understanding of the theory behind the establishment of a CCZ. However, the CCZ will continue to be a very difficult, if not impossible, aspect of the standard to implement from the perspective of practical application and compliance enforcement.
Response: The SDT thanks you for your response. The SDT feels that the tables are an important component and should be part of the standard. The supporting documentation for the derivation of the tables resides in the technical reference document. The revised standard does not use the concept of the CCZ.		
Tennessee Valley Authority	Disagree	TVA agrees with this concept however as stated in Comment Question 11 response, this should be an element of the White Paper and should not be in the Standard Requirement.

Organization	Question 12	Question 12 Comment
Response: The SDT thanks you for your response. The SDT feels that the tables are an important component and should be part of the standard. The supporting documentation for the derivation of the tables resides in the technical reference document.		
Exelon	Disagree	Comments: By using the Gallet equations, the draft standard appears to support reducing the clearance requirements as compared to IEEE 516. Given what we believe would be the difficulties in applying the clearances as developed using the Gallet equation method, we question if dropping the IEEE 516 guidance could have the unintended consequence of reducing reliability.
Response: The SDT thanks you for your response. The reduction in the clearance distances is due to applying smaller transient over-voltage factors and not due to using the Gallet equations. The SDT feels that using the reduced over-voltage factors is a more realistic approach than using the maximum factors in version 1. The Gallet equations are only one of the factors in developing clearances. The utility must also consider sag, sway, growth, environmental conditions and other factors when developing an effective TVMP.		
Northern Indiana Public Service Company	Disagree	If T.O.'s are serious about public safety and potential electrical hazards or are required to comply with NESC/IEEE safety standards, then the greater, more conservative clearance distances must apply. On an complex issue where the aerial distances between live conductors and trees are dynamic and changing, I would prefer to be on the side of caution and on the side of safety. Given the history of cascading blackouts due to preventable tree contacts, there is a need to be conservative with the standards. I don't see it being in the public interest to argue that established minimum air insulation distances are inappropriately restrictive when applied to UVM.
Response: The SDT thanks you for your response. The Gallet equations are only one of the factors in developing clearances. The utility must also consider sag, sway, growth, environmental conditions and other factors when developing an effective TVMP.		
Consumers Energy Company	Disagree	The Gallet distances severely lessen the reliability of the transmission system since there is not a define imminent threat distance and the Clearance 1 distances have been removed from this draft. The IEEE 516 distances provided a safety margin to allow for vegetation to grow and not be a reliability risk. A transmission owner/operator of a moderate size could not effectively inspect often enough during the growing season to protect lines from outages when trees are permitted to approach the Gallet formula distance and not be a violation. Such close distances would permit utility management to severely cut vegetation management budgets and allow trees to grow for 1-2 years beyond their scheduled maintenance cycle and not be in violation. But, 2-3 years after the budget cut, the field operation would be faced with an insurmountable amount of trees needing addressed and limited timeframes to complete the work. This is basically how the blackout occurred and this standard decreases the requirements to allow this to happen again.
Response: The SDT thanks you for your response. The Gallet equations are only one of the factors in developing clearances. The utility must also		

Organization	Question 12	Question 12 Comment
consider sag, sway, growth, environmental conditions and other factors when developing an effective TVMP.		
Baltimore Gas & Electric Company	Disagree	As noted in 11 above, the Gallet equation would appear to be a much closer approximation of the actual spark gap/flashover distance. It seems as though the new std. is making the protective zone around the conductors smaller by replacing the Clearance 2 requirement with the CCZ, while at the same time eliminating any other type of consideration for how much clearance needs to be achieved while trimming. All things being equal, if the only demarcation for when vegetation is a threat to the lines is the clearance 2 or CCZ areas, it would make sense to have this area be larger rather than smaller. Accordingly, I would recommend that the Clearance 2 value continue to be used instead of the Gallet equation-created CCZ.
Response: The SDT thanks you for your response. The Gallet equations are only one of the factors in developing clearances. The utility must also consider sag, sway, growth, environmental conditions and other factors when developing an effective TVMP. Note that the revised standard does not use the concept of the CCZ.		
SERC Vegetation Management Subcommittee (VMS)	Agree	Developing minimum sparkover distances in this standard is a superior approach for the stated reason in question 12. In addition, referring to tables and values in another standard is problematic if the referenced standard is revised and the tables are re-numbered or deleted altogether. We suggest that the tables based on the Gallet equations be removed from the standard and be kept in the technical white paper solely to assist in developing a common understanding of the threshold for taking actions.
Response: The SDT thanks you for your response. The SDT feels that the tables are an important component and should be part of the standard. The supporting documentation for the derivation of the tables resides in the technical reference document.		
SERC OC Standards Review Group	Agree	Developing minimum sparkover distances in this standard is a superior approach for the stated reason in question 12. In addition, referring to tables and values in another standard is problematic if the referenced standard is revised and the tables are re- numbered or deleted altogether. The SERC OOCSRG suggests that the tables based on the Gallet equations be removed from the standard and be kept in the technical white paper solely to assist in developing a common understanding of the threshold for taking actions.
Response: The SDT thanks you for your response. The SDT feels that the tables are an important component and should be part of the standard. The supporting documentation for the derivation of the tables resides in the technical reference document.		
Western Utility Arborists	Agree	The Western Utilities feel that changing this will not have a large impact on its vegetation management operations, so we have no concerns.
Response: The SDT thanks you for your response.		

Organization	Question 12	Question 12 Comment
American Electric Power (AEP)	Agree	AEP agrees that the Gallet Equation method is a reasonable and appropriate replacement for the IEEE 516 method.
Response: The SDT thanks you for your comments.		
Platte River Power Authority	Agree	Changing this will not have a large impact on vegetation management operations, so we have no concerns.
Response: the SDT thanks you for your comments.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	See comment for Question 11.
Response: The SDT thanks you for your response. The Gallet equations are only one of the factors in developing clearances. The utility must also consider sag, sway, growth, environmental conditions and other factors when developing an effective TVMP.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	We feel that changing this will not have a large impact on its vegetation management operations, so we have no concerns.
Response: The SDT thanks you for your comments.		
Salt River Project	Agree	As commented in Comment #11 above, although we agree that using the Gallet equation is more definitive than using IEEE 516, we still question from an engineering prespective as to how and why this method was chosen. It is stated in the Technical Reference paper that the Gallet Equation is a well known method of computing the required strike distance for proper insulation coordination. It is our understanding it's purpose is for designing towers, to define the "tower window" or opening inside of a tower under normal conditions. Because this is not a method design specifically for vegetation management, was there any physical testing involved in choosing this approach, such as testing in both wet and dry conditions? We would recommend additional information to clarify this method to use for vegetation management. See additional comments in Comment #18 below.
Response: The SDT thanks you for your response. The SDT searched for a method other than the laboratory condition based IEEE 516 method to determine minimum spark-over distances. The Gallet equations were derived for both wet and dry conditions and have been successfully used in many design applications. The SDT feels that using these equations to derive these minimum distances is a conservative approach. We also expect that the TO must also consider sag, sway, growth, environmental conditions and other factors when developing clearances for an effective TVMP.		

Organization	Question 12	Question 12 Comment
Buckeye Power, Inc.	Agree	I understand the reasoning for the change, but I do not see how decreasing clearances will increase reliability.
Response: The SDT thanks you for your response. The Gallet equations are only one of the factors in developing clearances. The utility must also consider sag, sway, growth, environmental conditions and other factors when developing an effective TVMP.		
British Columbia Transmission Corp	Agree	BCTC feels that changing this will not have a large impact on its vegetation management operations, so we have no concerns.
Response: The SDT thanks you for your response.		
Associated Electric Cooperative Inc.	Agree	
NPCC	Agree	
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
Progress Energy Florida	Agree	
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Progress Energy Carolinas	Agree	
Southern California Edison Company	Agree	Q12: No comments.

Organization	Question 12	Question 12 Comment
Florida Power & Light	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
Bonneville Power Administration	Agree	
FirstEnergy	Agree	
MRO NERC Standards Review Subcommittee	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	
ITC HOLDINGS	Agree	
Central Maine Power Company	Agree	
City of Tallahassee	Agree	
Northern California Power Agency (NCPA)	Agree	
Tampa Electric Company	Agree	
Orange and Rockland Utilities Inc.	Agree	
Ameren	Agree	

Organization	Question 12	Question 12 Comment
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Manitoba Hydro	Agree	
National Grid	Agree	
Pacific Gas & Electric Co.	Agree	
San Diego Gas & Electric	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Arizona Public Service Company	Agree	
Duke Energy Corporation	Agree	
CenterPoint Energy	Agree	
Entergy Services	Agree	
Pepco Holdings, Inc	Agree	
JEA	Agree	
Independent Electricity System	Agree	

Organization	Question 12	Question 12 Comment
Operator		
Northeast Utilities	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
Great River Energy	Agree	

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13. The Standard Drafting Team applied a transient overvoltage factor (T) of 1.4 and 2.0 for ac voltage classes of 345kV and above and sub-345kV facilities, respectively. Version 1, using the IEEE 516 method, assumes a maximum transient overvoltage value. The Standard Drafting Team asserts that in this application of steady-state flashovers and due to the design attributes of higher voltage systems, a lower T factor is applicable. Do you agree with this? If not, please explain.

Summary Consideration: The majority of responders (93%) agreed with this change. Two responders commented that they use a more conservative transient over-voltage factor in their design.

The SDT chose its transient over-voltage factors (“T”) as being the most appropriate values for the industry as a whole. The majority of industry stakeholder comments supported this decision. It is permissible to use more conservative values if the Transmission Owner so desires.

Organization	Agree ?	Question 13 Comment
BCTC		BCTC feels that changing this will not have a large impact on its vegetation management operations, so we have no concerns.
Response: The SDT thanks you for your response.		
Tennessee Valley Authority	Disagree	TVA agrees with this concept however as stated in Comment Question 11 response, this should be an element of the White Paper and should not be in the Standard Requirement.
Response: The SDT thanks you and refers you to the response to Question 11.		
Exelon	Disagree	We disagree with the T factors that are proposed as our design is more conservative.
Response: The SDT thanks you and also acknowledges that various utilities may employ various T factors in their line designs. However, the SDT chose this value as the most appropriate value for the industry as a whole. Individual Transmission Owners are free to establish larger zones around the conductor than that established by the new MVCD. MVCD as currently drafted establishes a minimum value, not the only value.		
Manitoba Hydro	Disagree	Manitoba Hydro has historically designed the ROW clearance requirements based on an operating limitation of not switching during extreme wind conditions, therefore, beyond a wind pressure of 230 Pa, our design does not account for switching surge over voltages. We do however, agree with the use of overvoltage factors

Organization	Agree ?	Question 13 Comment
		as described above for wind conditions of less than 230 Pa.
Response: The SDT thanks you for your comments. Industry as a whole. Individual Transmisssion Owners are free to establish larger zones around the conductor than that established by the new MVCD. MVCD as currently drafted establishes a minimum value, not the only value.		
National Grid	Disagree	No opinion.
Response: The SDT thanks you for your comments. The SDT believes that it has chosen an approach that is the most appropriate method for the industry as a whole.		
SERC Vegetation Management Subcommittee (VMS)	Agree	See comments in #12 above.
Response: The SDT thanks you for your comments. See response to #12.		
SERC OC Standards Review Group	Agree	See comments in #12 above.
Response: The SDT thanks you for your comments. See response to #12.		
Salt River Project	Agree	As commented in Comments #11 & #12 above, although we agree that using the Gallet equation is more definitive than using IEEE 516, we still question from an engineering prespective as to how and why this method was chosen. It is stated in the Technical Reference paper that the Gallet Equation is a well known method of computing the required strike distance for proper insulation coordination. It is our understanding it's purpose is for designing towers, to define the "tower window" or opening inside of a tower under normal conditions. Because this is not a method design specifically for vegetation management, was there any physical testing involved in choosing this approach, such as testing in both wet and dry conditions? We would recommend additional information to clarify this method to use for vegetation management. See additional comments in Comment #18 below.
Response: The SDT thanks you for your comments. No physical testing was utilized by the SDT; however, the Gallet Equation method and its explanation in the White Paper do have their basis in physical testing in both laboratory and field conditions. The Gallet Equation method is not solely applicable to tower structure design, but to any application requiring spark-over calculations. The SDT believes that the Gallet Equation method holds distinct advantages over the IEEE 516 method for use in vegetation management applications.		
Western Utility Arborists	Agree	The Western Utilities feel that changing this will not have a large impact on its vegetation management

Organization	Agree ?	Question 13 Comment
		operations, so we have no concerns.
Response: The SDT thanks you for your comments.		
American Electric Power (AEP)	Agree	AEP agrees that the choice of transient overvoltage factors is sufficiently sound.
Response: The SDT thanks you for your comments.		
Platte River Power Authority	Agree	Changing this will not have a large impact on vegetation management operations, we have not concerns.
Response: The SDT thanks you for your comments.		
City of Tallahassee	Agree	As long as we do not have to have evidence of using the calculation! We should be able to use Table I as provided.
Response: The SDT thanks you for your comments.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	We feel that changing this will not have a large impact on its vegetation management operations, so we have no concerns.
Response: The SDT thanks you for your comments.		
Southern California Edison Company	Agree	Q13: No comments.
Associated Electric Cooperative Inc.	Agree	
NPCC	Agree	
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
Progress Energy Florida	Agree	

Organization	Agree ?	Question 13 Comment
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Progress Energy Carolinas	Agree	
Florida Power & Light	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
Bonneville Power Administration	Agree	
FirstEnergy	Agree	
MRO NERC Standards Review Subcommittee	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	
Central Maine Power Company	Agree	
Northern California Power Agency (NCPA)	Agree	

Organization	Agree ?	Question 13 Comment
Tampa Electric Company	Agree	
Orange and Rockland Utilities Inc.	Agree	
Ameren	Agree	
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Consumers Energy Company	Agree	
Pacific Gas & Electric Co.	Agree	
San Diego Gas & Electric	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Arizona Public Service Company	Agree	
Duke Energy Corporation	Agree	
CenterPoint Energy	Agree	
Entergy Services	Agree	
Pepco Holdings, Inc	Agree	

Organization	Agree ?	Question 13 Comment
JEA	Agree	
Independent Electricity System Operator	Agree	
Northeast Utilities	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
Buckeye Power, Inc.	Agree	
Great River Energy	Agree	
Baltimore Gas & Electric Company		I have no expertise to respond to this question.
Northern Indiana Public Service Company		No comment.
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM		Don't know!

14. R3 has been added to clarify that conduction of inspections is a separate requirement from specifying the frequency that inspections will occur. Do you agree with R3? If not please explain.

Summary Consideration: The majority of commenters (85%) were in favor of the standard as written. There were minority comments that wanted a reformatting of the standard to put documentation and implementation side by side. Following the directives in FERC order 693 and the SAR to bring the standard in line with the Sanction Guidelines, the SDT created a separate requirement, R3 that explicitly requires inspections be conducted. This is to differentiate R3 from Requirement 1, Part 1.2. Addressing inspections separately allows for appropriate assignment of VRFs and VSLs.

Organization	Agree?	Question 14 Comment
BCTC		BCTC understands that it's possible to have a schedule and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the schedule is kept together with the requirement to implement it.
Response: The SDT thanks you for your comment. The SDT considered other sequence options and suggest a new sequence for the industry to comment upon. See related question in the second Comment Form.		
Western Utility Arborists		The Western Utilities understands that it's possible to have a schedule and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the schedule is kept together with the requirement to implement it.
Response: The SDT thanks you for your comment. The SDT considered other sequence options and suggest a new sequence for the industry to comment upon. See related question in the second Comment Form.		
Progress Energy Florida	Disagree	The standard has established a threshold of compliance. For consistency, compliance should be measured at the threshold not a Registered Entities program requirement.
Response: The SDT thanks you for your comments. R3 clarifies that the inspections in the TVMP are to be conducted. The TVMP defines a Transmission Operator's standards. The general application of NERC standards is that a Transmission Operator is to adhere to the standards it establishes.		
Progress Energy Carolinas	Disagree	The standard has established a threshold of compliance. For consistency, compliance should be measured at the threshold not a Registered Entities program requirement.
Response: The SDT thanks you for your comments. R3 clarifies that the inspections in the TVMP are to be conducted. The TVMP defines a Transmission		

Organization	Agree?	Question 14 Comment
Operator's standards. The general application of NERC standards is that a Transmission Operator is to adhere to the standards it establishes.		
Southern California Edison Company	Disagree	Q14: SCE does not agree with the inclusion of proposed R3 and believes it should be replaced with a modified version of proposed R8.SCE respectfully suggests that proposed R8 be revised to read: "Each Transmission Owner shall implement and follow its Vegetation Management Program to the extent allowed by existing easement and/or legal rights."
Response: The SDT thanks you for your comments. Inspections are a key element of an effective TVMP. The SDT therefore decided to explicitly require that inspections be conducted in accordance with the Transmission Owners' requirements. In addition, addressing inspections separately allows for appropriate assignment of VRFs and VSLs.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Disagree	We understand that it is possible to have a schedule and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the schedule is kept together with the requirement to implement it.
Response: The SDT thanks you for your comment. The SDT decided to explicitly require that inspections be conducted in accordance with the Transmission Owners' requirements. Addressing inspections separately allows for appropriate assignment of VRFs and VSLs.		
San Diego Gas & Electric	Disagree	The information should not be separated. It will be much easier to follow if the requirement to have the schedule is kept together with the requirement to implement it.
Response: The SDT thanks you for your comment. The SDT decided to explicitly require that inspections be conducted in accordance with the Transmission Owners' requirements. Addressing inspections separately allows for appropriate assignment of VRFs and VSLs.		
Edison Electric Institute	Disagree	Consistent with previous comments, NERC should respond to FERC Order No. 693 Paragraph 721 regarding compliance audit procedures to identify appropriate inspection cycles.
Response: The SDT thanks you for your comment. The SDT decided to explicitly require that inspections be conducted in accordance with the Transmission Owners' requirements. Your comment has been forwarded to NERC staff. The Reliability Standard Audit Worksheet is where the FERC Order is addressed with respect to compliance audit procedures to identify appropriate inspection cycles.		
Baltimore Gas & Electric Company	Disagree	If frequency of inspections are required to be specified, it is implied that the inspections will follow. I suggest that R3 be eliminated and R1.2 be reworded to say: "Vegetation inspections shall occur at least once per year, or more frequently as dictated by local and environmental factors. Specify the frequency of when vegetation inspections will occur."

Organization	Agree?	Question 14 Comment
Response: The SDT thanks you for your comment. The SDT decided to explicitly require that inspections be conducted in accordance with the Transmission Owners' requirements. Addressing inspections separately allows for appropriate assignment of VRFs and VSLs. The STD believes that the phrase "Specify a vegetation inspection frequency…" adequately requires the Transmission Operator to ". . . .specify the frequency…"		
JEA	Disagree	See comment from #3.
Response: The SDT thanks you for your comment. This was addressed in the response to question 3.		
Salt River Project	Disagree	The document would be easier to follow if the two elements would be kept together in the same requirement (similar to comments stated in Comments #4 & #6 above). It makes the standard longer than necessary and creates redundancy.
Response: The SDT thanks you for your comment. The SDT decided to explicitly require that inspections be conducted in accordance with the Transmission Owners' requirements. Addressing inspections separately allows for appropriate assignment of VRF and VSLs.		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 14
Response: The SDT thanks you for your comment.		
American Electric Power (AEP)	Agree	AEP agrees with this change.
Response: The SDT thanks you for your comment.		
Platte River Power Authority	Agree	The separation allows lower sanctions and penalties to be assessed for a weak schedule and higher sanctions and penalties to be assessed for not implementing schedules. However, we feel that the standard itself would be easier to follow if it was re-organized so that the requirement to have the schedule is kept together with the requirement to implement it.
Response: The SDT thanks you for your comment. The SDT decided to explicitly require that inspections be conducted in accordance with the Transmission Owners' requirements. Addressing inspections separately allows for appropriate assignment of VRFs and VSLs.		
Arizona Public Service Company	Agree	APS understands that it's possible to have a schedule and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the schedule is kept together with the requirement to implement it.

Organization	Agree?	Question 14 Comment
Response: The SDT thanks you for your comment. The SDT decided to explicitly require that inspections be conducted in accordance with the Transmission Owners' requirements. Addressing inspections separately allows for appropriate assignment of VRFs and VSLs.		
Associated Electric Cooperative Inc.	Agree	
NPCC	Agree	
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
SERC Vegetation Management Subcommittee (VMS)	Agree	
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
SERC OC Standards Review Group	Agree	
Florida Power & Light	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	

Organization	Agree?	Question 14 Comment
Bonneville Power Administration	Agree	
FirstEnergy	Agree	
MRO NERC Standards Review Subcommittee	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	
Exelon	Agree	
Central Maine Power Company	Agree	
City of Tallahassee	Agree	
Northern California Power Agency (NCPA)	Agree	
Northern Indiana Public Service Company	Agree	
Tampa Electric Company	Agree	
Orange and Rockland Utilities Inc.	Agree	
American Transmission	Agree	

Organization	Agree?	Question 14 Comment
Company		
Ameren	Agree	
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	
Manitoba Hydro	Agree	
Consumers Energy Company	Agree	
National Grid	Agree	
Pacific Gas & Electric Co.	Agree	
Hydro One Networks Inc.	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Duke Energy Corporation	Agree	
CenterPoint Energy	Agree	
Entergy Services	Agree	
Pepco Holdings, Inc	Agree	

Organization	Agree?	Question 14 Comment
Independent Electricity System Operator	Agree	
Northeast Utilities	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
Buckeye Power, Inc.	Agree	
Great River Energy	Agree	

15. Several alternatives to R4 were considered by the drafting team. The drafting team explored these significantly different alternatives at length. They are outlined below to provide background to industry during this comment period. (Please refer to pages 22-32 in the Technical Reference Document on the Critical Clearance Zone for further background for this question.) Do you agree that R4 is written in the most effective way to achieve the purpose of the standard? If not, what do you propose as an alternative to R4 that would ensure a level of reliability equal to or better than FAC-003-1?

As written, R4, a new requirement, stipulates that the Transmission Owner is in violation if an encroachment of the Critical Clearance Zone occurs at any time. If vegetation enters the Critical Clearance Zone, a violation will have occurred, regardless of the actual proximity of the vegetation to the conductor at the time. Evidence will be required to prove that no encroachments of the Critical Clearance Zone have occurred anywhere at any time during the annual compliance period. This will require the time and effort to postpone vegetation maintenance to perform field investigations and document all possible encroachments.

One alternative to R4 required immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the Critical Clearance Zone, thereby proactively preventing an outage. A violation would have occurred only if the imminent threat process was not successfully implemented.

Another alternative was a tiered approach. This tiered approach involved a "per thousand mile" metric to determine when a violation had occurred and the severity of the violation. This metric was an attempt to equitably account for varying exposures that exist due to widely ranging system sizes.

Summary Consideration: Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The Critical Clearance Zone has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.

Ninety-four percent of the commenters disagreed with the proposed alternatives. The SDT classified the comments into 44 different concepts with many commenters weighing in on several concepts. For 37 commenters the dominant concept was "Measure M4 requires proof of no encroachments, i.e., "prove a negative", compliance certification is difficult." Below is a redlined version of R4. reflecting the changes that were made by the SDT.

R4. Each Transmission Owner shall prevent encroachment of vegetation into the Minimum Vegetation Clearance Distances ("MVCD") listed in Attachment 1 for its applicable lines as observed in real-time operating between no-load and their Rating with the following exceptions: *[Violation Risk Factor VRF= Medium][Time Horizon – Real Time]*

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- Encroachment into the Minimum Vegetation Clearance Distances listed in Attachment 1 resulting from natural disasters.[2]
- Encroachment into the Minimum Vegetation Clearance Distances listed in Attachment 1 resulting from human or animal activity.[3]
- Brief encroachment into the Minimum Vegetation Clearance Distances listed in Attachment 1 resulting from falling vegetation.

The SDT further weighed the NERC interpretation of the vegetation management standard during FERC's consideration of proposed FAC-003-1: A vegetation-related transmission line outage as a result of vegetation that has grown into the pre-defined clearance zone is a violation of the standard. The Commission adopted that interpretation when it approved NERC's proposed reliability standards. It stated, "FAC-003-1 requires sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions."4

In reviewing the comments and the FERC opinion the SDT considered 4 options:

- Re-word R4 and keep R4 the way it was originally intended (violation would only be if you had the outage) (Alternative B of Question 15**) {implies that R5, R6, & R7 are retained}
- Remove R2 and R4 from the standard. Keep the Critical Clearance Zone concept in the white paper.
- Remove R4 from the standard and revise R2 to have a "trigger distance" for implementation of the imminent threat process. Keep the Critical Clearance Zone concept in the white paper. Team would need to consider the true definition of an imminent threat.
- Return to the Clearance 2 concept. But define (somehow) that this is a "real time" violation only. Distance could be defined as the Gallet distance or a multiple of the Gallet distance.

The SDT made the following changes in line with bullet 4.

R4. Each Transmission Owner shall prevent encroachment of vegetation into the Minimum Vegetation Clearance Distances (MVCD) listed in FAC-003-2 - Attachment 1 for its applicable lines as observed in real-time operating between no-load and their Rating, with the following exceptions:

- Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from natural disasters.[4]

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[2] Examples include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods.

[3] Examples include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation.

- Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from human or animal activity.[5]
- Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from falling vegetation.

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Organization	Agree?	Question 15 Comment
PJM Interconnection		The current version of this standard, FAC-003-1, kept the subject of vegetation outside of the Rights of Way in the standard. Why are outside of Rights of Way vegetation issues not mentioned in FAC-003-2, or some responsibility for looking for outside of Rights of Way imminent threats or issues requiring corrective action plans not addressed?
Response: The SDT thanks you for your comments. Trees outside of the right of way should be identified and removed as necessary as they are identified as a threat to the reliability of the line. This function should be part of a vegetation management program as a follow up to the inspection process. Any vegetation that could pose a threat to the reliability to the line found during the inspection process should be remedied. The purpose statement for FAC-003-2 states that the standard is intended to improve the reliability of the electric transmission system by preventing vegetation related outages that could lead to Cascading.		
BCTC		The new requirement in R4 stipulates that the Transmission Owner is in violation if an encroachment of the CCZ occurs at any time. However, the CCZ changes with each foot of the transmission line from the insulator to the mid-span, depending on loading, actual operating temperature, wind loading, ice loading, maximum design rating, maximum operating load, and so on. Further, Measure M4 requires that the Transmission Owner has evidence demonstrating there were no vegetation encroachments into the CCZ. These requirements may result in having to LIDAR the lines annually, to prove that trees have not encroached upon the CCZ. This would be an extremely onerous and expensive requirement for utilities. BCTC strongly supports the alternative to R4 as recommended in the Comment Form (#15), which is to require immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the CCZ, thereby proactively preventing an outage. This means a violation would occur only if the imminent threat process is not successfully implemented. This alternative is essentially the same as R2. Therefore, BCTC recommends removing R4 from the standard entirely.

[4] Examples include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods.

[5] Examples include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation.

Organization	Agree?	Question 15 Comment
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Associated Electric Cooperative Inc.	Disagree	Associated Electric Cooperative Inc believes this requirement, as written, is unreasonable since it would prevent (or at least result in noncompliance) the intrusion within the Critical Clearance Zone (CCZ) of anything or anyone, including qualified line workers and their tools. It is suggested the words "of vegetation" be added between encroachment and within. The requirement would then read, "Each Transmission Owner shall prevent encroachment of vegetation within the Critical Clearance Zone of its applicable lines with the following exceptions:" The complexity of determining an encroachment into the Critical Clearance Zone is overly burdensome, requiring engineering calculations and possibly the need for precision measurements. The Transmission Owner (TO) cannot demonstrate compliance with the Requirement and its companion Measure, M4, since a negative cannot be proven. Therefore, since the TO must demonstrate compliance (guilty until proven innocent), it is automatically in violation of the Standard.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time. The SDT, for clarity, did add the phrase "of Vegetation" as requested.		
NPCC	Disagree	The purpose of the standard is "To improve the reliability of the Bulk Electric System by preventing vegetation related outages that could lead to Cascading". We believe that R4 is not the most effective way to achieve this purpose because it does not provide incentive for Transmission Owners to take advantage of modern technology, such as aerial laser survey (ALS) using Light Detection and Ranging technology (LIDAR), that is capable of accurately identifying vegetation which is approaching the CCZ or has encroached into it. In fact R4 provides an incentive not to utilize this technology because Transmission Owners who identify encroachments would be in violation of R4 for each identified encroachment. On the other hand, Transmission Owners who choose to be less proactive often would not identify such encroachments because the CCZ and encroachments of it are generally not easy to determine without taking precise measurements. Unless the line is heavily loaded or the vegetation is significantly overgrown, encroachments of the CCZ would not be readily noticed. In most cases these Transmission Owners would simply remove or cut back incompatible vegetation without taking measurements. The threat to the line would have been eliminated with no encroachment having been identified.R4 presents a dilemma for Transmission Owners that are considering making the significant investment in ALS technology. While the technology would allow them to identify any potential grow-in or fall-in conditions, it would also expose them to the risk of identifying violations of R4, that would otherwise not have been identified. Violation Risk Factors

Organization	Agree?	Question 15 Comment
		(VRFs), Violation Severity Levels (VSLs), and Time Horizons are not included in this Draft, but after making a significant investment in ALS, Transmission Owners could be faced with significant additional cost in terms of NERC penalties. In addition, even if the penalties were relatively low they would be exposing themselves to violations that less proactive Transmission Owners would not be exposed to. In our view R4 as written would, in some cases, have the opposite effect of what is intended because the business case for using ALS is more difficult to make. This will result in less use of ALS and other emerging technology that is likely to be developed. This would result in fewer problems being identified, a small percentage of which will not be discovered until they result in a line trip. Still we believe that the concept of the CCZ is a good one and recommend that R4 be changed so that Transmission Owners are provided with an incentive to invest in the best technology available in order to ensure the highest level of reliability. The opportunity exists to develop the standard in a manner that encourages the industry to take advantage of new technology and manage vegetation in a very proactive way. We recommend that R4 be changed as follows: Modify R4 to require Transmission Owners to immediately implement the imminent threat process defined in R1.4 when they identify instances where the CCZ is approached or encroached upon. Failure to do so would be a violation of R4. Eliminate encroachment of the CCZ as a violation of R4. This would eliminate R2 and incorporate implementation of the imminent threat process into R4.Require Transmission Owners to report to the Regional Entity on a quarterly basis any instances where the imminent threat process was implemented due to an encroachment of the CCZ. This would add a reporting requirement for Transmission Operators. Require Transmission Owners to report to the Regional Entity on a quarterly basis any instances where either a momentary or sustained outage was caused by grow-ins, Active Transmission Line Right of Way blow-ins, or Active Transmission Line Right-of-Way fall-ins. This would add three additional reporting requirements for Transmission Operators. Require Regional Entities to perform additional audits of Transmission Owners that exceed metrics for violations of the CCZ . The metrics would be established in this Standard based upon 100 circuit miles of applicable lines. This would add an additional requirement for Regional Entities. This concept would result in a more rigorous standard than FAC-003-01 because of the additional reporting and auditing requirements. It would drive proactive behavior throughout the industry and provide a significant incentive for Transmisison Owners to invest in new technology such as ALS that is capable of accurately identifying vegetation that has approached or encroached upon the CCZ. We believe that this change would result in the identification of more incipient vegetation-related problems and fewer vegetation-related outages as soon as it was implemented and would best support the purpose of the Standard.

Response: The SDT thanks you for your comments. The SDT concurs that the use of ALS – LiDar technology, while expensive, could enhance reliability. However several team members have made the investment and concur that the technology including interpertation software are not sufficiently mature to be put in a standard. In addition in some cases it would not be cost justifiable over traditional methods of inspection. During the course of our deliberations the team questioned both FERC and RE staff's response to a utility finding encrochments with ALS technology and concluded the auditor would not forgive encrochment even though the Transmission Owner went to extraordinary means to find the encrochment.

Initially the team approached the FERC staff in a meeting in Washington with a proposal that an encrochment not be a violation if the Transmission Owner implemented the imminent threat procedure successfully before an interruption occurred. The concept was rebuffed by the FERC Staff as a step

Organization	Agree?	Question 15 Comment
backwards from version 1. **The SDT very carefully and thoroughly examined the merits, disadvantages, ease and difficulties of assessing momentary outages as a violation. The result of that effort led to the more precise and field observable aspects of R4. It should be noted that by their very nature the exact causes of "momentary outages" are very challenging to determine and will vary widely from utility to utility. The SDT did not find that such variability was appropriate for a reliability standard, and chose to address this issue with the language in R4.** **Due to the industry impact that arises from zero tolerance for vegetation-related sustained outages, the Drafting Team tried several approaches but could not find a mechanism in the standard development process to establish a non-zero threshold for outages that was acceptable to FERC staff because Standard revisions to already approved standards may not lead to less emphasis on reliability.**		
Western Area Power Administration, Upper Great Plains Region	Disagree	R4 as proposed would do nothing to improve the reliability of the BES. In fact, we believe that R4 (as currently proposed) would impose significantly more stringent requirements than most Transmission Owners have interpreted FAC-003-1 to require. We believe that if the proposed interpretation would have been offered under FAC-003-1 that there would have be a great backlash against that Standard. It is our believe that current annual certifications of compliance for FAC-003-1 by Transmission Owners don't use "any infringement of the CCZ by any piece of vegetation at any time" as their measure for compliance. It could be argued that this proposal would actually do more to curtail accurate reporting of potential violations. We believe that making an infringement into the CCZ a violation and having that violation carry a six (or seven) figure fine would do more to discourage accurate reporting than any other system under discussion. Making the Transmission Owner prove that an incursion into the CCZ didn't happen would force an inventory of every inch of the R/W which is a gigantic waste of resources. Being tasked with proving that something didn't happen could be compared with our justice system declaring suspects will be considered guilty until they are proven innocent. This is a flawed and blatantly unfair concept and not a productive way of attaining the Purpose stated in this document. Western (UGPR) is disappointed by the "zero tolerance" nature of this document and its interpretation that "any infringement of the CCZ by any piece of vegetation at any time" constitutes a violation. We are not aware of any other NERC standard that is zero tolerance and question why vegetation is singled out to bear the brunt when several other factors could contribute to a system cascading event (i.e. relay problems, system configuration, operator issues, etc). In summation, we believe that a zero tolerance document being applied with "guilty until proven innocent" principles would do much to create an increasingly adversarial relationship between regulators and the industry.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
SERC Vegetation Management Subcommittee (VMS)	Disagree	The concept of the CCZ is useful as a mental model to visualize required vegetation management work. While this is a good conceptual tool to drive consistent terminology and proper vegetation management practices, it remains theoretical in nature and impractical to measure on a span by span basis. The complexity of determining

Organization	Agree?	Question 15 Comment
		an encroachment into the CCZ is overly burdensome due to the need for survey accuracy measurements and engineering evaluations. In addition, this complexity leads to questions about the ability to audit this requirement. These complexities introduce reliability and audit issues when encroachments into this conceptual area are defined as violations. The SERC VMS believes the Sustained Outage, as defined by other measures in this standard, should be the non-compliance measure. We suggest that the CCZ concept be kept in the technical white paper and that all references to the CCZ be removed from the body of the standard.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Progress Energy Florida	Disagree	The definition of Critical Clearance Zone includes too many academic and theoretical elements. It is impossible to provide evidence that vegetation did not encroach into the Critical Clearance Zone during TVMP cycles. Furthermore, the operations staff performing periodic ground and aerial inspections would need to determine the CCZ for each foot of transmission line to assure compliance with the standard as it is currently written. The CCZ concept can neither be implemented or enforced as written. The CCZ refers to Ratings which is defined in the Glossary of Terms as "The operational limits of a transmission system element under a set of specified conditions." This definition is too broad to be a consistently enforceable term from one utility or region to the next. As it is currently written, no exemption exists for vegetation falling from outside the Active Transmission Line Right of Way into, or lodging in, the theoretical CCZ.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Kansas City Power & Light	Disagree	As proposed, Requirement R4 and corresponding Measure M4 will be highly subjective and impractical for the industry to implement. The determination of a violation due to encroachments into the Critical Clearance Zone will be subjective in nature due to field judgments, is random and not initiated by a known system event. It also will not be feasible for utilities to fulfill R4 requirements to ensure and provide evidence that any encroachments into Critical Clearance Zones have not occurred on their system throughout the year. Requirement R4 is not required since in the remaining requirements of FAC-003-2 contain the principal elements for compliance in ensuring the reliability of the bulk power system related to vegetation management of the transmission system. Specifically, the remaining requirements provide that a transmission vegetation plan be maintained, implemented and regularly reviewed whereby utilities must perform the requisite vegetation clearance work in order to prevent any sustained outages on the bulk power system. A sustained outage due to vegetation is a known, measurable event to which a penalty sanction will be invoked and therefore provides the required impetus for adherence to standard FAC-003-2.Requirement R4 and the associated measure M4 should therefore be removed from the proposed standard

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		language.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Western Area Power Administration, Rocky Mountain Region	Disagree	As discussed in the Technical Reference document and question #11 above, the CCZ is a complicated theoretical envelope surrounding all rated operating positions of the conductor. Its dynamic shape is constantly changing and is contingent upon location within the span. Calculation of the size and shape of CCZ is based, in part, upon the design parameters of the transmission facility. However, as-built or long term maintenance conditions can often diverge from the original design requirements over time. Ground elevations can also change as a result of man made or natural causes from the original design elevations recorded on plan and profile engineering drawings. Consequently, accurate field measurement of the as-built CCZ is extremely problematic and strategies that utilize the calculation of allowable right-of-way tree heights can be hindered by unrecorded deviations from the original design criteria. Allowable tree height strategies also become increasingly more difficult and impractical with increasing extremes in terrain. While the CCZ is a very important concept for an effective vegetation management program it is far to theoretical, dynamic, and impractical to field measure for use as a clear and precise boundary for regulatory purposes. As such, R4 as written should be deleted from the Standards. Further, the requirement to provide evidence of something that has not occurred (no vegetation encroachments of the CCZ) is also impractical. General industry interpretation of R1.2.2 in version 1 of the Standards is that the specific Clearance 2 distance is the precise boundary that is not to be encroached verses the broader area that is ultimately mapped out as the conductor moves through "all rated electrical operating conditions". Only the Clearance 2 distance value is a clear, precise number that can be accurately observed and measured in the field. If there is a persistence to retain the CCZ concept as a requirement within the Standards, the second bullet option above regarding the initiation of the imminent threat process upon discovery of a possible encroachment is the preferred option. Since a potential encroachment into the CCZ is not a violation under this option, exact determination of the CCZ boundary is no longer as essential. Rather, the focus is on triggering mitigation to vegetation problems to prevent outages. However, as with question #11 above, there is still no practical way to determine for regulatory purposes those "potential encroachment" situations that legitimately require initiation of the imminent threat process from those "potential encroachment" situations that do not. Under this option the utility is really motivated to initiate the imminent threat process to avoid an impending outage. As such, the occurrence of an outage becomes the only clear, precise and observable means to determine a Standards violation. A proposed alternative to ensure a level of reliability equal to or better than FAC-003-1 is to retain the Clearance 2 requirement (without the imprecise "all rated electrical operating conditions" language) in combination with the sustained outage requirements of R5, R6 and R7. If an additional margin of safety is determined to be required, industry performance can be adjusted to become more proactive by increasing the minimum Clearance 2 distance to a value greater than the proposed version 2 Gallet equation (table 1) values. Thinking in terms of the

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		CCZ concept, it is obvious that a larger Clearance 2 value translates into a larger CCZ envelope. A larger CCZ envelope in turn triggers mitigation for possible CCZ encroachments sooner.
Response: The SDT thanks you for your comments and proposed alternatives. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Progress Energy Carolinas	Disagree	The definition of Critical Clearance Zone includes too many academic and theoretical elements. It is impossible to provide evidence that vegetation did not encroach into the Critical Clearance Zone during TVMP cycles. Furthermore, the operations staff performing periodic ground and aerial inspections would need to determine the CCZ for each foot of transmission line to assure compliance with the standard as it is currently written. The CCZ concept can neither be implemented or enforced as written. The CCZ refers to Ratings which is defined in the Glossary of Terms as "The operational limits of a transmission system element under a set of specified conditions." This definition is too broad to be a consistently enforceable term from one utility or region to the next. As it is currently written, no exemption exists for vegetation falling from outside the Active Transmission Line Right of Way into, or lodging in, the theoretical CCZ.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Southern California Edison Company	Disagree	Q15: SCE does not agree that proposed R4 was written in the most effective way because it establishes a zero tolerance enforcement policy. SCE agrees that a CCZ incursion should be addressed promptly, but we do not agree that a CCZ incursion is equivalent to a vegetation-to-line contact, or that a CCZ incursion represents an imminent threat of flash-over. As written, proposed R4 would require Transmission Owners to prove that a Critical Clearance Zone incursion has not occurred. Short of a daily ground or aerial inspection of every applicable transmission line, it is clearly impossible for a Transmission Owner to monitor their active Right of Way on a 24/7/365 basis to ensure a CCZ incursion will not or has not occurred. Bearing in mind that even the most robust of Transmission VM programs may occasionally identify an anomalous condition (in or outside the active ROW) that left untreated could lead to a flash-over or vegetation-to-line contact, the identification of such conditions typically occur during scheduled aerial or ground patrols and addressed timely. Of the two alternatives offered, SCE finds the first option (second bullet item) to be the most palatable. However, even that option leaves significant doubt as to practical enforcement, because a Transmission Owner could still be found in violation of two separate requirements (R4 and R5, R4 and R6 or R4 and R7) should a vegetation-to-line contact (resulting in a sustained outage) occur. This situation amounts to regulatory double jeopardy. SCE believes that by any reasonable legal or regulatory measure, requiring a Transmission Owner to prove that a CCZ incursion did not

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		occur is impractical and virtually impossible to enforce in a fair and impartial manner. Further, SCE believes that proposed R4 and corresponding M4 detracts from the purported goal of FAC-003-2 and should be removed.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
SERC OC Standards Review Group	Disagree	The requirement, as written, compels the Transmission Operator to allocate precious resources to ensuring that a vegetation encroachment NEVER will occur on any transmission line, regardless of that line's true importance to maintaining electric transmission system reliability. All lines are not created equal; only those that are involved in IROLs should be held to a zero tolerance standard. R4, if retained, should begin with "Subject to its legal rights," and insert the word "vegetation" between prevent and encroachment. Vegetation, which falls through the Critical Clearance Zone or falls to lodge within the Critical Clearance Zone, should not be included as violations of the Critical Clearance Zone. The concept of the Critical Clearance Zone is useful as a mental model to visualize required vegetation management work. While this is a good conceptual tool to drive consistent terminology and proper vegetation management practices, it remains theoretical in nature and impractical to measure on a span by span basis. The complexity of determining an encroachment into the Critical Clearance Zone is overly burdensome due to the need for survey accuracy measurements and engineering evaluations. In addition, this complexity leads to questions about the ability to audit this requirement. These complexities introduce reliability and audit issues when encroachments into this conceptual area are defined as violations. The SERC OCSRG believes the Sustained Outage, as defined by other measures in this standard, should be the non-compliance measure. We suggest that the Critical Clearance Zone concept be kept in the technical white paper and that all references to the Critical Clearance Zone be removed from the body of the standard. R5, R6, and R7 ensure that version 2 of the standard has reliability requirements equal to version 1; therefore R4 should be removed.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time. The SDT, for clarity, did add the phrase "of Vegetation" as requested.		
Western Utility Arborists		The new requirement in R4 stipulates that the Transmission Owner is in violation if an encroachment of the CCZ occurs at any time. However, the CCZ changes with each foot of the transmission line from the insulator to the mid-span, depending on loading, actual operating temperature, wind loading, ice loading, maximum design rating, maximum operating load, and so on. Further, measure M4 requires that the Transmission Owner has evidence demonstrating there were no vegetation encroachments into the CCZ. To provide evidence demonstrating there were no vegetation encroachments into the CCZ would be an extremely onerous task and an expensive requirement for the Utilities. The Western Utilities strongly supports the alternative to R4 as recommended in the

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		Comment Form (#15), which is to require immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the CCZ, thereby proactively preventing an outage. This means a violation would occur only if the imminent threat process is not successfully implemented. This alternative is essentially the same as R2. Therefore, the Western Utilities recommend removing R4 from the standard entirely.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Florida Power & Light	Disagree	NERC standards require the Transmission Owner certify annually that they are in compliance to the standard for the entire year. Since there is no way that a Transmission Owner could monitor every span of line every minute of every day, Requirement R4 cannot be certified. A Transmission owner can only certify that at the time inspected the system met the specification in the standard and that implementation of its Transmission Vegetation Management Plan maintains these specifications. As stated earlier, the Critical Clearance Zone is difficult to accurately identify in the field and without an outage it would be difficult for an auditing body to find and validate. Requirements R4-R7 are reactive in nature. They are violations after the event has occurred or when the tree -wire relationships are so close that emergency action is the only recourse for the Transmission Owner. The standard needs to drive the Transmission Owner to identify and remove trees threatening the system in a proactive fashion. A Transmission Owner should never be in violation for timely action to remove a threat to the system.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Santee Cooper	Disagree	Recommend replacing the word "prevent" in R4 to "monitor". The first alternative that requires immediate removal of vegetation or immediate implementation of the imminent threat procedure would be a Requirement that could be measured. In addition, if an encroachment is found it needs to be eliminated and the first alternative specifies immediate removal. If R4 is left as written, how can you provide evidence that there has been no encroachments within the Critical Clearance Zone.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		

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Southern Company	Disagree	The Critical Clearance Zone is a concept that adequately describes the salient functionality a Transmission Owner must consider when determining acceptable clearances. However, the practicality of a requirement that forbids even one encroachment in the Critical Clearance Zone presents a problem for not only the field personnel doing the vegetation work, but also the Regional Entity that must enforce the requirement. This zone changes not only from one span to another, it also changes at each location along each span. The reality is that the difference in encroaching into the zone and not encroaching into the zone is a matter of a fractional inch. In order to prove non-compliance or to defend compliance at a particular site, all vegetation work would have to be postponed for survey accuracy equipment and appropriately trained personnel to be brought to the site, measurements and calculation to be made and consequently a determination rendered. This hardly seems worthwhile when the vegetation could simply be cut, the threat removed and the vegetation work could continue on down the transmission line. As stated in a previous comment, there could be many examples given of encroachments into this theoretical zone that would neither threaten the transmission line conductor nor cause a reduction in the capacity of the transmission line. This concept would be better suited to be a “trigger point” that, if found, would be incentive for the Transmission Owner to either take immediate action or ensure future activities are appropriately scheduled and implemented. This action may be as urgent as implementation of the immediate threat procedure or as non-urgent as making sure that the upcoming maintenance on that line is scheduled appropriately. If a sustained outage occurs due to an encroachment, the outage should be the compliance measure.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
E.ON U.S.	Disagree	The concept of the Critical Clearance Zone is useful as a mental model to visualize required vegetation management work. While this is a good conceptual tool to drive consistent terminology and proper vegetation management practices, it remains theoretical in nature and impractical to measure on a span by span basis. The complexity of determining an encroachment into the Critical Clearance Zone is overly burdensome due to the need for survey accuracy measurements and engineering evaluations. In addition, this complexity leads to questions about the ability to audit this requirement. These complexities introduce reliability and audit issues when encroachments into this conceptual area are defined as violations. We believe the Sustained Outage, as defined by other measures in this standard, should be the non-compliance measure. We suggest that the Critical Clearance Zone concept be kept in the technical white paper and that all references to the Critical Clearance Zone be removed from the body of the standard.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		

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Bonneville Power Administration	Disagree	R4 states that the Transmission Owner is in violation of the Standard if the Critical Clearance Zone is encroached upon. The CCZ, as defined by the Standard, changes along the transmission line from the insulator to mid-span, depending on loading, actual operating temperature, wind and ice loading, maximum design rating and operating load, etc. Also, the tandem, Measure M4, requires that the Transmission Owner has evidence demonstrating that there has been no vegetation encoachments in the CCZ along its transmission system. In order to meet the letter of the Standard, that is to provide evidence that no encroachments in the CCZ have occurred under all manner of these fluid environmental and operating conditions, the Transmission Owner would have to employ the highest level of modeling technology available, which would seem to be LiDAR technology. The standard should not be written in such a manner so that it requires, by all intent and purpose, a Transmission Owner to acquire a particular technology. BPA recommends that the Alternative represented by "the second bullet" above, be used rather than R4 in its present state, or that R.4. be simply dropped and R1.4 modified to state that the imminent threat procedures include immediate removal of encroachments into the Critical Clearance Zone. Also, the term "immediate" implies instantaneous response. The use of another term is recommended, such as "as immediate as human health and safety considerations allow, in order to prevent the possibility of flashover".
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Public Service Electric and Gas Company	Disagree	An additional clarifying exception in the footnotes to R4 consisting of a tree that is located off of the transmission owner's right of way falling into the CCZ should be added to the encroachment exceptions. Transmission owners should not be found in violation of the standard for falling vegetation located off of the TO's property.
Response: The SDT thanks you for your comments. The SDT has added the exception you requested. Note that the exception applies to any falling vegetation regardless of its location. **3. Brief encroachment into the Minimum Vegetation Clearance Distances listed in Attachment 1 resulting from falling vegetation.**		
FirstEnergy	Disagree	Providing evidence to prove that there were no encroachments of the CCZ is difficult at best. An occurrence of an encroachment does not necessarily translate to an outage. The CCZ is dynamic and difficult to measure exactly from span to span and day to day and is dependent on environmental and line conditions. The costs to comply with this requirement as written are difficult to justify considering that reliability may not be improved at all. FirstEnergy believes that the first alternative above should be used and is a more logical approach from both a reliability and compliance standpoint. Furthermore, since the first alternative is already covered by the currently proposed wording of R2, the only changes needed to the standard are to remove the proposed R4 and M4 and re-number the requirements.

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Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
MRO NERC Standards Review Subcommittee	Disagree	The MRO believes R4 should be eliminated as vegetation contacts are covered in R5 and R6. A violation should only occur with a vegetation contact. Assessing a violation and fine for a potential reduction in system reliability is not correct. Actual contacts that trip a transmission element have some measurable impact on system reliability even if it is slight.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Midwest ISO Stakeholders Standards Collaborators	Disagree	The second bulleted alternative above is the best approach, but it should be improved by changing the imminent threat trigger from "encroachment of the CCZ" to "encroachment within some observed, field distance that is a multiple of the Gallet distances referenced in Table I". We have recommended changes to accomplish this in Requirement R2 (see our response to Question #11 above), and R4 should simply be deleted. While the CCZ is valuable to understanding the movement of conductors, it cannot be readily applied in the field. This field application challenge is noted in the Technical Reference Document (pages 29 & 30).The way R4 is currently stated, the Transmission Owner would be in violation of R4 for any CCZ encroachment not due to natural disasters or human or animal activity. This would include a tree falling from outside the right of way corridor that passes through the theoretical CCZ. Furthermore, Transmission Owners would be required to self-certify compliance with R4, and we don't think there's any way to do that. Clearly the approach of assessing violations for CCZ encroachment is unworkable. Likewise, the third alternative listed above is untenable. The tiered approach could have a mitigating effect on violations, but it would require the same inspection effort and postponement of vegetation management that makes the first alternative unworkable. Both the first and third alternatives would require very significant additional expenditures for surveys and documentation in an impossible attempt to certify compliance - money that would be better spent controlling vegetation.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time. The proposed standard revision specifies the MVCD as a starting point and TO's may apply multiples at their own discretion in order to achieve their TVMP objectives and adhere to applicable safety standards.		
SERC Compliance Staff	Disagree	The concept of the Critical Clearance Zone is useful as a mental model to visualize required vegetation

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		management work. While this is a good conceptual tool to drive consistent terminology and proper vegetation management practices, it is impractical to measure on a span by span basis. The complexity of determining an encroachment into the Critical Clearance Zone is overly burdensome due to the need for survey accuracy measurements and engineering evaluations. While it may be a technically sound approach to designate the clearance zone to be tied to the conductor movement envelope as found in the NESC, this results in a banana-shaped zone that is difficult to substantiate in the field by entity and compliance personnel. We suggest that the Critical Clearance Zone concept be kept in the technical white paper and that all references to the Critical Clearance Zone be removed from the body of the standard.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
ITC HOLDINGS	Disagree	First, it’s impossible to determine that no encroachments into the CCZ have occurred at any time and determination of the CCZ from the field perspective is problematic. The standard is ambiguous and it seems like clear cutting is the underlining message that is wanted. Determining an encroachment into the CCZ is problematic due to the need for survey accuracy measurements and engineering evaluations. This will also lead to questions about the ability to audit this requirement. The CCZ changes in size and shapes continuously in each and every span and will be difficult to monitor. This would require field personnel to spend numerous hours estimating and attempting to measure potential encroachments of the CCZ. The way R4 is currently written the Transmission Owners would be required to self-certify compliance with R4, and which we don’t think this is possible. This will lead to audit issues with more scrutinizing and potentially more penalties or fines. It is important to recognize that the ultimate goal of the standard is to ensure that vegetation management is conducted in order to maintain an adequate level of reliability, and not to precisely measure clearance zones. Alternative 2 would be the most logical choice, depending on easement/legal rights, with changes that would eliminate any reference to a trigger point into the encroachment zone of the CCZ to; measuring encroachment to a fix distance (Gallet tables) observed by field personnel
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Tennessee Valley Authority	Disagree	TVA recommends that R4 be removed from this standard. Since this is a "zero tolerance" standard with substantial penalties for controllable vegetation related outages there is an overwhelming incentive for the Transmission Owner to proactively perform inspections, preventative maintenance, inpections and corrective maintenance to prevent potential outages. As such, R4 does not add any value to improving reliability while causing numerous

Organization	Agree?	Question 15 Comment
		unresolvable problems.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Exelon	Disagree	The first bullet is unworkable in the real world. It will be virtually impossible to prove that "no encroachments of the CCZ have occurred anywhere at any time during the compliance period". The effort to do this will not enhance reliability. In fact, in may harm reliability by requiring unnecessary investments and O&M expenditures that could be better spent on real reliability enhancements. Exelon agrees, subject to the development of a workable definition of the CCZ, that the second bullet is the preferred approach.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Central Maine Power Company	Disagree	Central Maine Power Company suggests the second alternative to R4 as recommended above, which is to require immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the critical clearance zone, thus preventing an outage. This alternative is similar to R2, therefore R4 may not be required.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
American Electric Power (AEP)	Disagree	AEP disagrees with the proposed requirement that violations be automatically declared if the CCZ is encroached. Instead, AEP would support a standard utilizing the first alternative proffered in these comment questions. While the CCZ is an interesting theoretical concept, it is not realistically feasible in the field to implement a concept that depends on accurate measurements and calculations. Further, the proposed requirement offends common notions of reliable maintenance methods, because it demands that forestry crews stop work if they see a potential encroachment and that surveyors and engineers be brought in to take detailed measurements and perform complex calculations to determine whether an encroachment has in fact occurred. The need for a reliable transmission grid would be much better served by a standard utilizing the first alternative, in which no violation occurs in the event of an encroachment as long as the TO implements its imminent threat procedure and removes the vegetation. While seemingly technically appealing, the CCZ concept is fraught with implementation difficulties. It should not be used as a Pass/Fail zero-tolerance decision point to determine whether a violation has occurred.

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		After all, a zero-defect condition has not been achieved in many other aspects of electric utility operation. For instance, the utility industry attempts every year to conduct its business without any workplace deaths, yet deaths occur every year. Many millions of dollars are spent by North American utilities to promote safety programs and safe work procedures, but some work-related vehicle accidents and personal injuries still occur. Also, utilities aggressively investigate electric switching errors and have instituted rigorous dispatcher-training programs, but a few switching errors still occur. For an industry in which billions of stems of vegetation must be managed, even a high six-sigma level of quality would still result in a few cases annually of imperfectly managed vegetation. It is unreasonable to expect zero-tolerance perfection with the CCZ concept. Also, with the way R4 is worded, a tree falling from outside the right of way would result in a violation if it passed through the CCZ, whether it resulted in an outage or not. It is not appropriate to place a burden on the TO for such circumstances outside the TO's control. As R4 is written, it appears that there is no way that a TO could certify at the end of the year that it has maintained a CCZ free of encroachments, even if no outages occurred. AEP believes a more effective and reliability-centered approach would be one where TOs are expected to implement their imminent threat procedure if vegetation is encroaching upon the Gallet equation distance. If TOs act accordingly and remove the vegetation without incurring an outage, then they would not be in violation. However, if the TOs knew of vegetation encroaching upon the Gallet equation distance but failed to implement their imminent threat process, they would be in violation and be obliged to report the event.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Platte River Power Authority	Disagree	This requirement should be removed completely. It is too stringent and it is impossible to prove compliance through documentation. Encroachemnt of Clearance 2 (or CCZ) should be addressed in the imminent threat procedure.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
City of Tallahassee	Disagree	VEHEMENTLY DISAGREE! The purpose of the standard is to prevent vegetation related outages. A violation should occur if an outage occurs. As written, R4 and M4 would be impossible to prove or disprove. It is not like we can get up there with a tape measure and measure it. R2 requires action if the CCZ is "approached". This is undefined and subject to a myriad of interpretations. Evidence is hard enough to obtain to the satisfaction of the Compliance Monitor. To require sufficient evidence to prove that something didn't occur is a tremendous burden and is not a wise expenditure of vegetation management dollars. Let us spend the money on trimming and not on paperwork. As an alternative replace "encroachment within the Critical Clearance Zone" with "vegetation caused

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		outages". This would allow the same exceptions and is much easier to prove or disprove with a breaker operation. Although this would result in the cause of every breaker operation being tracked, it is a tangible evidence requirement and leaves very little room for interpretation. The levels of fines have already shown that vegetation management is a serious standard and we had better comply.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Northern Indiana Public Service Company	Disagree	It will be impossible for a T.O. to provide "evidence" that no encroachments of the C.C.Z. occurred at any time during the year. This approach will be a compliance nightmare and is unworkable. How does one prove this never happens? You can't monitor every span of every line at all times. Obviously, whenever a T.O. has a preventable outage, that should be a violation. To address the issue of preventing outages before they occur and penalizing T.O.'s who don't take proper steps to prevent them, I prefer the approach of immediate removal of threatening vegetation that encroaches within a "threat trigger/action threshold" clearance distance per the T.O.'s formal imminent threat procedure. This "threat trigger/action threshold" clearance would be established by the T.O. and be a specific requirement under a revised FAC-003.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Tampa Electric Company	Disagree	This is a good start. The Critical Clearance Zone (CCZ) is a very real and practical concept; however, it is not transferable to field conditions. This could result in a "fill in the blank" standard relative to what the Critical Clearance Zone will be in terms of distance. As I read this, it will be a sliding scale from insulator to mid span and back for each designated line voltage. The max wind speed to be used and other assumptions behind the determination of this zone may be as involved a Gallet's formula. This will lead to complications during operational inspection and verification of these clearances.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Orange and Rockland Utilities Inc.	Disagree	We believe that R4 is not the most effective way to achieve the purpose of the Standard. As previously stated the CCZ and encroachments of it are generally not possible to identify in the field without taking precise measurements. The CCZ changes in size and shape continuously throughout each and every span. In many

Organization	Agree?	Question 15 Comment
		cases the CCZ can be very large, and the position of the conductor with respect to encroaching vegetation within the CCZ can be relatively far apart. Such cases would typically not be identified as encroachments of the CCZ by visual inspections. Only those instances where the vegetation is significantly overgrown would be readily identifiable. R4, as written presents a problem in terms of compliance, certification of compliance, and auditing because precise measurements of every span are impractical and costly to perform. Certification of compliance would require field personnel to spend valuable time estimating and attempting to measure potential encroachments of the CCZ. R4 does not provide incentive for Transmission Owners to deploy modern technology that is better able to identify encroachments of the CCZ with a reasonable amount of accuracy, such as ALS and LIDAR which are described in the response to Question 11. In fact R4 might provide an incentive not to utilize this technology because Transmission Owners who identify encroachments using ALS which would otherwise not have been identified would be in violation of R4. Transmission Owners that choose to be less proactive often would not identify such encroachments and would be at less risk of violating R4. The effect could be less frequent use of ALS and other technology that may emerge. This would result in fewer problems being identified, a small percentage of which may not be discovered until they result in a line trip. We believe that the best way to achieve the purpose of this Standard is to encourage proactive behavior which prevents vegetation-related outages throughout the entire industry. R4 does not achieve this in the most effective way. We recommend the following: Eliminate encroachment of the CCZ as a violation of R4. Require Transmission Owners to immediately implement the imminent threat process defined in R1.4 when they identify instances where vegetation has grown within a specific distance as described in the response to Question 11 regarding R2. This would essentially combine R2 and R4.Require Transmission Owners to report to the Regional Entity any instances where the imminent threat process was implemented due to a vegetation-related clearance encroachment. This would add a reporting requirement for Transmission Owners. Require Regional Entities to perform additional audits of Transmission Owners that exceed metrics for vegetation-related clearance encroachments. The metrics should be established in the Standard based upon 1000 circuit miles of applicable lines. This would add an additional requirement for Regional Entities. Modify R5, R6, and R7 to include preventing momentary outages as well as Sustained Outages. We believe that this concept would result in a more rigorous standard because of the additional requirements, but would focus the industry's attention in a more effective fashion. We believe it would result in fewer vegetation-related interruptions and a higher level of reliability soon after implementation, and would therefore best support the purpose of the Standard.

Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.

The SDT very carefully and thoroughly examined the merits, disadvantages, ease and difficulties of assessing momentary outages as a violation, and chose to address this issue with the language in R4.

Organization	Agree?	Question 15 Comment
American Transmission Company	Disagree	While the CCZ is valuable to understanding the movement of conductors, it cannot be readily applied in the field. This field application challenge is noted in the Technical Reference Document (pages 29 & 30).The way R4 is currently stated, the Transmission Owner would be in violation of R4 for any CCZ encroachment not due to natural disasters or human or animal activity. This would include a tree falling from outside the right of way corridor that passes through the theoretical CCZ. Furthermore, Transmission Owners would be required to self-certify compliance with R4, and ATC does not think there is a practical way to do that. Clearly, the approach of assessing violations for CCZ encroachment is unworkable. ATC believes that R4 should be deleted.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Xcel Energy	Disagree	The way this requirement is written may require a utility to prove a negative. In other words, prove that we did not have trees encroaching into the CCZ at any time. This is impossible to prove. We propose the following language: ?The TO shall not have a encroachment within the CCZ which was not dealt with by utilizing the imminent threat procedure before experiencing a Sustained Outage, with the following exceptions 1) Encroachment of the CCZ that result for natural disasters 2) Encroachment of the CCZ that result from human or animal activity."
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Ameren	Disagree	The second bulleted alternative above is the best approach, but it should be improved by changing the imminent threat trigger from "encroachment of the CCZ" to "encroachment within some observed, field distance that is defined in the Plan. This would allow Transmission Owners to define for field personnel a CCZ that accomplishes some multiple of the Gallet distances referenced in Table I" but is easy to determine and apply. We have recommended changes to accomplish this in Requirement R2 (see our response to Question #11 above), and R4 should simply be deleted. While the CCZ is valuable to understanding the movement of conductors, it cannot be readily applied in the field. This field application challenge is noted in the Technical Reference Document (pages 29 & 30).The way R4 is currently stated, the Transmission Owner would be in violation of R4 for any CCZ encroachment not due to natural disasters or human or animal activity. This would include a tree falling from outside the right of way corridor that passes through the theoretical CCZ. Furthermore, Transmission Owners would be required to self-certify compliance with R4, and we don't think there's any way to do that. Clearly the approach of assessing violations for CCZ encroachment is unworkable. Likewise, the third alternative listed above is untenable. The tiered approach could have a mitigating effect on violations, but it would require the same

Organization	Agree?	Question 15 Comment
		inspection effort and postponement of vegetation management that makes the first alternative unworkable. Both the first and third alternatives would require very significant additional expenditures for surveys and documentation in an impossible attempt to certify compliance - money that would be better spent controlling vegetation.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Nebraska Public Power District	Disagree	NPPD disagree with an encroachment being a violation. A lot of time would need to be spent to determine if an encroachment occurred and in a self regulating environment, reporting would be minimal if any. The Transmission Owner would be in violation for any non natural event. Even a tree falling into the ROW passing through CCZ would be in violation of R4. Difficult at best to enforce. We need to spend time keeping the ROW cleared and less time inspecting for possible encroachments.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Long Island power Authority	Disagree	The Standard is about preventing outages and having an effective program. An effective program should allow for the identification of a threat and the removal of the threat prior to a vegetation caused outage. I prefer alternative 2. If a vegetation caused outage should occur or if the Regional Entity determines a violation occurred based on a compliance investigation then the entity is in violation of this requirement.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Disagree	The wording appears too strong. Who can predict the unforeseen circumstances that inevitably arise. If the standards require the reporting of encroachments, the ensuing report can help determine if the Transmission Owner did everything reasonable to avoid the problem. It seems like the standard should be written to require the Transmission Owner to do everything reasonable to avoid the problem. A judgment call would still be needed to evaluate the performance.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		

Organization	Agree?	Question 15 Comment
Manitoba Hydro	Disagree	Manitoba Hydro asserts that the reliability of the system is measured by outage, not by the possibility of an outage, and therefore if the overall vegetation management system (plan-patrol-discover-mitigate) is effective in preventing an outage, then the reliability of the system has been maintained, and the intent of the reliability standard achieved. Therefore, we propose that the second bullet above is the preferred alternative, and that R2 and R4 be combined as the violation of R4 would then imply a violation of R2.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Consumers Energy Company	Disagree	The CCZ does not provide adequate clearance and the imminent threat procedure if successfully implemented only works IF YOU KNOW ABOUT THE VEGETATION THAT THREATENS THE CCZ which cannot be ensured with yearly inspections. Consumers Energy believes that the Clearance 2 distances in FAC-003-1 provide more reliability than the CCZ proposed in this draft or any of the alternatives disused above.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Pacific Gas & Electric Co.	Disagree	PG&E believes a "minimum clearance distance" or "do not encroach zone" is a critical element of this standard and necessary to achieve the stated purpose of preventing vegetation caused outages. Preventing vegetation encroachments will prevent outages. However, PG&E disagrees with using the CCZ as a minimum clearance requirement because it is ambiguous and subject to wide variations and interpretation. CCZ is a good concept to aid in understanding movement of conductors but is a theoretical calculation and would be very difficult if not impossible to enforce. PG&E suggests using a clearly defined distance such as Gallet equation plus a safety margin to assure there is no chance of spark over. Two times Gallet would be a reasonable clearance requirement to assure a spark over does not occur and eliminate the ambiguity of the CCZ as the "do not encroach zone".
Response: The SDT thanks you for your comments. The SDT discussed the Gallet plus alternative suggested by PG&E. Due to the tremendous variation of design standards, the team decided that the decision as to how much a margin for error to use belonged to the individual TO. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time. The threat of a violation is believed sufficient to motivate a Transmission Owner to maintain a larger clearance.		

Organization	Agree?	Question 15 Comment
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Disagree	The new requirement in R4 stipulates that the Transmission Owner is in violation if an encroachment of the CCZ occurs at any time. However, the CCZ changes with each foot of the transmission line from the insulator to the mid-span, depending on loading, actual operating temperature, wind loading, ice loading, maximum design rating, maximum operating load, and so on. Further, Measure M4 requires that the Transmission Owner has evidence demonstrating there were no vegetation encroachments into the CCZ. These requirements may result in having to LIDAR the lines annually, to prove that trees have not encroached upon the CCZ. This would be an extremely onerous and expensive requirement for utilities. NV Energy strongly supports the alternative to R4 as recommended in the Comment Form (#15), which is to require immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the CCZ, thereby proactively preventing an outage. This means a violation would occur only if the imminent threat process is not successfully implemented. This alternative is essentially the same as R2. Therefore, we recommend removing R4 from the standard entirely.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
San Diego Gas & Electric	Disagree	The new requirement in R4 stipulates that the Transmission Owner is in violation if an encroachment of the Critical Clearance Zone (CCZ) occurs at any time. However, the CCZ changes with each foot of the transmission line from the insulator to the mid-span, depending on loading, actual operating temperature, wind loading, ice loading, maximum design rating, maximum operating load, and so on. Further, Measure M4 requires that the Transmission Owner have evidence demonstrating there were no vegetation encroachments into the CCZ. These requirements may result in having to LIDAR the lines annually to prove that trees have not encroached upon the CCZ. This would be an extremely oerous and expensive requirement for utilities. We strongly support the alternative to R4 as recommended in the Comment Form, which is wto require immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the CCZ, thereby proactively preventing an outage. This means a violation would occur only if the imminent threat process is not successfully implemented. This alternative is essentially the same as R2. Therefore, we recommend removing R4 from the standard entirely.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Hydro One Networks Inc.	Disagree	A statement is needed that this requirement applies to the active right of way. Outside of the active right of way there is no guarantee that this can be achieved. As noted in the question above, it may be very difficult with the

Organization	Agree?	Question 15 Comment
		first alternative to provide adequate evidence that no encroachment had occurred over the compliance period, as the situation is very difficult to assess along each span to the accuracies (1/100 of a foot) spelled out for the CCZ. It may be more meaningful that the Transmission Owners be able to demonstrate processes, methodologies and actions that can support that vegetation has not entered the CCZ. Another alternative for R4 could then be: Each Transmission Owner shall demonstrate that adequate actions and processes are in place to prevent vegetation from entering the CCZ. The effectiveness of the process can then be evaluated based on methods used for field assessment and performance, i.e., outages and imminent threat reporting. It appears that the second alternative noted above can be combined with R2. It is not clear why there needs to be a separate requirement. Hydro One is not in favour of alternative 3, as this would create added administration with a situation that will be difficult to prove to the accuracy required. LIDAR may be the only means available to provide evidence of a quality needed to produce meaningful statistics, and in many cases this may not be the most efficient use of the limited funding that is available.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Edison Electric Institute	Disagree	Encroachment without a Sustained Outage should not be construed as a violation. The proposed R4 requirement should be removed. EEI strongly believes that this requirement, if approved, is unenforceable. The alternative, to require implementation of the imminent threat procedure, should be considered as a practical approach. In particular, this concern applies to a requirement to prove that no encroachments have existed. This will require extensive work by field personnel, who will be required to make subjective judgments. In addition, determining actual clearance zones in the field would require a span-by-span analysis to be conducted with the rigor of survey level measurements. Calculations made to determine the clearance zones are based on undefined terms and subject to wide variation. Enforcement authorities will be required to make interpretations. EEI believes that the costs of conducting such work will not deliver sufficient benefit to warrant the requirement. Ultimately, there is no basis for determining whether the theoretical clearance zones included in the proposed standard will increase, or even maintain, an adequate level of reliability as provided by the existing standard.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Consolidated Edison Company of New York (CECONY)	Disagree	CECONY disagrees with R4 as currently written. As mentioned in the response to Question 15, performing a field measurement of the CCZ and a field measurement of the vegetation encroaching into the CCZ are complicated, time-consuming efforts. As the CCZ changes along the conductor, so too may the Active ROW dimensions, the vegetation clearances at multiple points, and elevation levels to name a few. Certifying compliance that no

Organization	Agree?	Question 15 Comment
		encroachments have occurred would be very difficult for auditors and field inspectors. Modern laser technology would have to be deployed to take these measurements and CECONY is concerned that, if an encroachment of the CCZ constitutes a violation, utilities would not consider investing in this technology knowing that multiple violations could potentially be found within a single span. Enhanced reliability is achieved when utilities invest in the best available technology and perform proactive inspections on their systems but, as written, R4 would not effectively motivate a utility to follow through with these initiatives. We recommend that the term 'momentary outage' or the phrase 'all outages' be used in R5, R6, and R7 instead of 'Sustained Outages' to avoid confusion throughout the industry. Momentary outages identify a potential failure of the utility's vegetation management program and stating it directly in the Standard clearly sends the message to utilities that all vegetation outages are unacceptable. In summary, we do not agree that encroachments are violations but we do recommend that when a utility identifies vegetation-related imminent threats and takes immediate action, they report this to their Reliability Coordinator. The Reliability Coordinator (RC) could then identify the utilities that have had multiple issues or have exceeded acceptable pre-established reporting limits which, in turn, would help the RC prioritize auditing efforts. This, in our opinion, would enhance reliability more effectively.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time. **The SDT very carefully and thoroughly examined the merits, disadvantages, ease and difficulties of assessing momentary outages as a violation. The result of that effort led to the more precise and field observable aspects of R4. It should be noted that by their very nature the exact causes of “momentary outages” are very challenging to determine and will vary widely from utility to utility. The SDT did not find that such variability was appropriate for a reliability standard, and chose to address this issue with the language in R4.**		
Arizona Public Service Company	Disagree	APS agrees with alternative one. The new requirement in R4 stipulates that the Transmission Owner is in violation if an encroachment of the CCZ occurs at any time. However, the CCZ changes with each foot of the transmission line from the insulator to the mid-span, depending on loading, actual operating temperature, wind loading, ice loading, maximum design rating, maximum operating load, and so on. Further, Measure M4 requires that the Transmission Owner has evidence demonstrating there were no vegetation encroachments into the CCZ. These requirements may result in having to LIDAR the lines annually, to prove that trees have not encroached upon the CCZ. This would be an extremely onerous and expensive requirement for utilities. APS strongly supports the alternative to R4 as recommended in the Comment Form (#15), which is to require immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the CCZ, thereby proactively preventing an outage. This means a violation would occur only if the imminent threat process is not successfully implemented. This alternative is essentially the same as R2.

Organization	Agree?	Question 15 Comment
		Therefore, APS recommends removing R4 from the standard entirely.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Baltimore Gas & Electric Company	Disagree	One concern with the proposed wording is that the verbiage seems to provide a loophole that will count any fallen tree, or tree with the potential to fall from inside or outside of the R/W (that doesn't meet the criteria in footnotes 4 & 5) that passes or could pass through the CCZ, and that may or may not cause an outage, would qualify as a violation in the std. There is no other language that I can detect in the std. that counters this point. Determination of whether or not a fallen tree, or tree with the potential to fall would qualify would be predicated upon height measurements of the fallen or standing tree(s) relative to the CCZ at max. engineered sag. An alternative wording suggestion is: "Each Transmission Owner shall prevent encroachment within the Critical Clearance Zone of it's applicable lines associated with trees that meet the criteria for grow-ins from on or off the Active right-of-way. Fall-ins from inside or outside of the active right-of-way are not applicable to this sub-requirement." If the occurrence is a violation, reporting of the incident will be an ethical issue and rely on the honesty of the inspector or whomever finds the problem. If it's not a violation, it will be more likely that the incident will be reported and can be treated as "Near Miss' reports are with respect to safety incidents - they provide valuable input to help forestall future more serious incidents. Consequently, I recommend that no violation occur as long as the 'Imminent Threat Procedure' is implemented. Further, if there is no violation associated with Imminent Threat Procedure implementation, I would suggest that falling or standing trees originating from within the active right-of-way that encroached or could encroach in the CCZ be added to the requirement to enhance the 'Near Miss' data pool.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Duke Energy Corporation	Disagree	The second bulleted alternative above is the best approach, but Duke believes it should be improved by changing the imminent threat trigger from "encroachment of the CCZ" to "encroachment within some observed, field distance that is a multiple of the Gallet distances referenced in Table I". We have recommended changes to accomplish this in Requirement R2 (see our response to Question #11 above), and R4 should simply be deleted. While the CCZ is valuable to understanding the movement of conductors, it cannot be readily applied in the field. This field application challenge is noted in the Technical Reference Document (pages 29 & 30).The way R4 is currently stated, the Transmission Owner would be in violation of R4 for any CCZ encroachment not due to natural disasters or human or animal activity. This would include a tree falling from outside the right of way corridor that passes through the theoretical CCZ. Furthermore, Transmission Owners would be required to self-certify compliance with R4. The technological requirements for accurately certifying compliance would be impossible to

Organization	Agree?	Question 15 Comment
		administer. Clearly the approach of assessing violations for CCZ encroachment is unworkable. Likewise, the third alternative listed above is untenable. The tiered approach could have a mitigating effect on violations, but it would require the same inspection effort and postponement of vegetation management that makes the first alternative unworkable. Both the first and third alternatives would require very significant additional expenditures for surveys and documentation in an impossible attempt to certify compliance - money that would be better spent controlling vegetation.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
CenterPoint Energy	Disagree	It is not reasonable to expect Transmission Owners to devote resources, both human and financial, to prove that vegetation never encroached into the Critical Clearance Zone, anytime-anywhere. R4 and M4 should be deleted.R2 and M2 are sufficient in ensuring a level of reliability equal to or better than FAC-003-1 with some minor wording changes to adopt similar wording of the alternative to R4 that was considered by the drafting team that includes "immediate implementation of the imminent threat procedure" for imminent threats of a vegetation related Sustained Outage in lieu of a nebulous "encroachment of the Critical Clearance Zone". According to the Technical Reference, it is "nearly impossible to field correlate and accurately 'superimpose' the Critical Clearance Zone around the conductor". It not likely that the Transmission Owner will know when the Critical Clearance Zone is approached through field observation. The previous Clearance 2 provided for a specific radial clearance from the conductor that was much easier to observe. (See comments to Q3 above.)
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Entergy Services	Disagree	1. Entergy believes that outages caused by vegetation are the most reasonable and objective measures for a violation which is not consistent with the proposed R4. See additional comments in section 16 related to R5, 6, and 7. 2. If R4 remains, Entergy proposes that the most reasonable approach to this requirement is a variation of the second bulleted option. This variation would include wording clarifying that only known encroachments of the Critical Clearance Zone would be considered violations. Entergy is willing to include failures to enact the imminent threat process (which is really a violation of R2) and also known vegetation inside the Critical Clearance Zone. This variation should continue to include the exceptions for natural disaster and human activities. 3. Determining objective, quantifiable encroachments into the Critical Clearance Zone is very challenging in field operations because such determination may require a degree of accuracy only obtainable using survey equipment

Organization	Agree?	Question 15 Comment
		or other sophisticated, costly measuring devices. 4. Entergy is concerned about the challenges of uniform audit ability due to noted uncertainties and the statement of absolute criteria that have to be shown in the negative. If the first bullet option is approved for R4, Entergy suggests the sentence “Evidence will be required to prove that no encroachments of the Critical Clearance Zone have occurred anywhere at the any time during the annual compliance period” be deleted. It is very difficult in regulatory terms to attest that no vegetation has ever crossed the Critical Clearance Zone during the time period being reviewed given the wide range of potential conditions that may not have been detected or even been detectable unless the conditions afforded direct observation. Too many assumptions would have to be made for an entity to self certify to this requirement. If R4 is implemented as stated, those assumptions need to be stated and clarified. 5. If any version of R4 is approved, Entergy suggests that the standard include an exception for trees falling from off the right of way and encroaching the Critical Clearance Zone. For example, a tree that falls from off the right of way. During the fall towards the conductor, the tree could possibly break the Critical Clearance Zone without causing an outage or even a threat of an outage yet still be a violation of the proposed standard. 6. If the second bulleted item is approved, it should be altered to read “a violation would have occurred only if no vegetation imminent threat process was initiated.” 7. Entergy does not feel the third bulleted item is adequately defined to use as a requirement in the standard at this time. 8. Conditions for blow-out, in the development of the Critical Clearance Zone, need to be defined in the standard. Their inclusions, in the white paper only, are not appropriate, as well.
Response: The SDT thanks you for your comments and suggested alternatives. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time. The SDT addressed your item 5 in subpart 3 in R4. This exception would apply to any falling vegetation outside the right of way or inside the right of way.		
Pepco Holdings, Inc	Disagree	As discussed in our response to Q11, the concept of encroachment into the Critical Clearance Zone is flawed. It is enforceable almost exclusively through self reports. R5, R6 and R7 provide all incentives for the TO to follow its inspection and maintenance plans, and R2, if properly written to remove references to the Critical Clearance Zone provides additional incentives. R4 is not needed and should be deleted. PHI is puzzled where this concept came from. Nowhere in Order 693 is this concept discussed.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon		

Organization	Agree?	Question 15 Comment
substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time. The concept of the CCZ was originally intended to provide an area that could be used to produce a metric for less than “zero tolerance” however that did not materialize.		
JEA	Disagree	As written, demonstration of compliance may not be feasible and would certainly be prohibitively expensive, consuming resources better spent managing vegetation. In general, putting entities in the position of proving something didn't occur is exptremely difficult and burdensome, without really aiding reliability. If the incident was significant, the region would know about it, and investigations can be pursued, if warranted. The first alternative requiring implementation of the imminent threat procedure is a better choice.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Salt River Project	Disagree	Disagree with R4 as it is written. The new requirement in R4 stipulates that the Transmission Owner is in violation if an encroachment of the Critical Clearance Zone occurs at any time. However, the Critical Clearance Zone changes with each foot of the transmission line from the insulator to the mid-span, depending on loading, actual operating temperature, wind loading, ice loading, maximum design rating, maximum operating load, and so on. See additional comments in Comment #18 below. Furthermore, Measure M4 requires that the Transmission Owner has evidence demonstrating there were no vegetation encroachments into the Critical Clearance Zone. To provide evidence demonstrating there were no vegetation encroachments into the Critical Clearance Zone would be an extremely onerous task and an expensive requirement for the utilities. We strongly support changing this to the 1st alternative written in Comment #15 "One alternative to R4 required immediate removal of the vegetation or immediate implementation of the immenent threat procedure upon discovery of a possible encroachment of the Critical Clearance Zone, thereby proactively preventing an outage. A violation would have occurred only if the immenent threat process was not successfully implemented." This alternative is essentially the same as R2, therefore, we recommend removing R4 from the standard entirely.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Northeast Utilities	Disagree	First - the determination of the CCZ is highly problematic in the field. Second - it is impossible for any utility to certify that no encroachments have occurred at any time unless a utility has completely removed all potentially interferring vegetation on all areas of their transmission system. If the standard is to clear-cut and maintain a tree free right of way, the standard should say so. To determine if vegetation may have violated the CCZ the inspector

Organization	Agree?	Question 15 Comment
		must know at the time of the inspection the ambient temperature, the wind speed, the loading of the line and the actual distances between the vegetation and conductors. Then, the information must be compared to possible extreme operating levels of the line under all conditions to know if the vegetation may violate the CCZ. As stated - it is improbable that this could accurately be performed in the field as the data changes within each segment of a span's length. The first alternative provides the most effective means of addressing encroachment of the CCZ - having an encroachment is not a violation - knowing there is an encroachment and not correcting the problem would be a violation. Implementing the imminent threat procedure and correcting the problem is a more effective approach. Having a zero tolerance for encroachments of the CCZ under all situations and operating conditions would sub-optimize the use of resources. No actual event may have occurred on the system, yet the utilities will be in violation just for a possible or potential problem that even under extreme operating conditions may not actually occur. It would be best if the violations were limited to "known encroachments" (not "possible encroachments") such as would occur if a line were to trip due to vegetation contact, or if there is evidence of any burns. If no action was taken on known encroachments to correct the problem (such as implementation of the imminent threat procedure) then a violation will have occurred. It is doubtful that any utility will be able to certify that at no time has vegetation encroached into the CCZ. Utilities will have to spend an untold amount of resources to verify that there have not been any encroachments during a compliance period - instead of using these resources more effectively in taking proactive measures to manage and control encroaching vegetation. As written, any encroachment into the CCZ is considered a violation of FAC-003-2 (R4). There are exceptions provided for encroachments due to natural disasters and human or animal activity. There is no exception for encroachments due to the failure of a tree(s) outside of the active transmission line ROW. Based on R4, a trip and reclose of a transmission line (no outage) is a violation even if the tree is outside of the active right-of-way; whereas per R6 and R7, a line outage would not be a violation if the tree was outside of the active right-of-way. As written - this is not clear - there should be exceptions to allow for trees falling into the CCZ (and into the active transmission line right-of-way) from outside the limits of the active transmission line right-of-way. Also - how are violations of the CCZ requirement to be reported - there is no provision for the reporting process and requirements (specifics on the type of violation). Will this be addressed in the Compliance Section yet to be added?
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Hydro-Quebec Transenergie (HQT)	Disagree	The purpose of the standard is "To improve the reliability of the Bulk Electric System by preventing vegetation related outages that could lead to Cascading". We believe that R4 is not the most effective way to achieve this purpose because it does not provide incentive for Transmission Owners to take advantage of modern technology, such as aerial laser survey (ALS) using Light Detection and Ranging technology (LIDAR), that is capable of accurately identifying vegetation which is approaching the CCZ or has encroached into it. In fact R4 provides an incentive not to utilize this technology because Transmission Owners who identify encroachments would be in

Organization	Agree?	Question 15 Comment
		violation of R4 for each identified encroachment. On the other hand, Transmission Owners who choose to be less proactive often would not identify such encroachments because the CCZ and encroachments of it are generally not easy to determine without taking precise measurements. Unless the line is heavily loaded or the vegetation is significantly overgrown, encroachments of the CCZ would not be readily noticed. In most cases these Transmission Owners would simply remove or cut back incompatible vegetation without taking measurements. The threat to the line would have been eliminated with no encroachment having been identified.R4 presents a dilemma for Transmission Owners that are considering making the significant investment in ALS technology. While the technology would allow them to identify any potential grow-in or fall-in conditions, it would also expose them to the risk of identifying violations of R4, that would otherwise not have been identified. Violation Risk Factors (VRFs), Violation Severity Levels (VSLs), and Time Horizons are not included in this Draft, but after making a significant investment in ALS, Transmission Owners could be faced with significant additional cost in terms of NERC penalties. In addition, even if the penalties were relatively low they would be exposing themselves to violations that less proactive Transmission Owners would not be exposed to. In our view R4 as written would, in some cases, have the opposite effect of what is intended because the business case for using ALS is more difficult to make. This will result in less use of ALS and other emerging technology that is likely to be developed. This would result in fewer problems being identified, a small percentage of which will not be discovered until they result in a line trip. Still we believe that the concept of the CCZ is a good one and recommend that R4 be changed so that Transmission Owners are provided with an incentive to invest in the best technology available in order to ensure the highest level of reliability. The opportunity exists to develop the standard in a manner that encourages the industry to take advantage of new technology and manage vegetation in a very proactive way. We recommend that R4 be changed as follows: Modify R4 to require Transmission Owners to immediately implement the imminent threat process defined in R1.4 when they identify instances where the CCZ is approached or encroached upon. Failure to do so would be a violation of R4. Eliminate encroachment of the CCZ as a violation of R4. This would eliminate R2 and incorporate implementation of the imminent threat process into R4.Require Transmission Owners to report to the Regional Entity on a quarterly basis any instances where the imminent threat process was implemented due to an encroachment of the CCZ. This would add a reporting requirement for Transmission Operators. Require Transmission Owners to report to the Regional Entity on a quarterly basis any instances where either a momentary or sustained outage was caused by grow-ins, Active Transmission Line Right of Way blow-ins, or Active Transmission Line Right-of-Way fall-ins. This would add three additional reporting requirements for Transmission Operators. Require Regional Entities to perform additional audits of Transmission Owners that exceed metrics for violations of the CCZ. The metrics would be established in this Standard based upon 100 circuit miles of applicable lines. This would add an additional requirement for Regional Entities. This concept would result in a more rigorous standard than FAC-003-01 because of the additional reporting and auditing requirements. It would drive proactive behavior throughout the industry and provide a significant incentive for Transmisison Owners to invest in new technology such as ALS that is capable of accurately identifying vegetation that has approached or encroached upon the CCZ. We believe that this change would result in the identification of more incipient vegetation-related problems and fewer vegetation-related outages as soon as it was implemented and

<table>
<tr><th>Organization</th><th>Agree?</th><th>Question 15 Comment</th></tr>
<tr><td></td><td></td><td>would best support the purpose of the Standard.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comments and suggestions. The reporting and documenting concept that you suggest has been incorporated in part in R2. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.</td></tr>
<tr><td>Buckeye Power, Inc.</td><td>Disagree</td><td>Proving vegetation is not in a clearance zone will be difficult without having third-party verification.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.</td></tr>
<tr><td>Great River Energy</td><td>Disagree</td><td>GRE supports the elimination of R4, as vegetation contacts are covered in R5 and R6. A violation should only occur with a vegetation contact. Assessing a violation and fine for a potential reduction in system reliability is not correct. Actual contacts that trip a transmission element have some measurable impact on system reliability even if it is slight. In the event that the SDT chooses not to eliminate R4, GRE would also support the alternative language that is shown under the second bullet.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.</td></tr>
<tr><td>WECC</td><td>Agree</td><td>Yes, R4 as written provides clear guidance to TOs on the minimum radial distance, dependant on line voltage that vegetation is allowed to approach energized conductors. These industry standardized distances will ensure a level of reliability equal to or better than FAC-003-1.</td></tr>
<tr><td colspan="3">Response: The SDT thanks for your comments. Please see the summary consideration for this question – based on other comments, the SDT made significant revisions to Requirement R4. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.</td></tr>
<tr><td>National Grid</td><td>Agree</td><td>National Grid agrees that there should be no encroachments into the CCZ. However, encroachments in the CCZ should NOT be considered a violation. Violations should only be for sustained transmission outages.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and</td></tr>
</table>

Organization	Agree?	Question 15 Comment
Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Northern California Power Agency (NCPA)	Agree	
WECC Reliability Coordination	Agree	
Response: The SDT thanks you for your positive feedback. Most commenters disagreed with R4. Changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		

16. Requirements R5, R6, and R7 define that Sustained Outages due to vegetation growing into, blowing together with, and falling into transmission lines are violations (subject to certain exemptions). Therefore, all such outages must be reported as violations of the standard. Do you agree with this change? If not, please explain.

Summary Consideration: Seventy two percent of the respondents agreed with the changes. Multiple commenters made the following points: Questionable cost benefit, not all lines are equal, complicated and burdensome to know precisely where edge of ROW is, the standard should read minimize outages and not prevent them. The majority of the team did not agree there was sufficient argument to support making changes to the requirements based on the comments.

Several commenters pointed out that debris that has been detached from the tree and blown into the conductor and trees from outside the ROW should be exempt. The team adjusted the standard to accommodate debris and falling from outside the ROW.

Organization	Agree?	Question 16 Comment
Western Utility Arborists		The Western Utilities strongly recommend that the requirement under R7 be changed from “shall prevent sustained outages” to “shall minimize sustained outages due to vegetation falling into a conductor.” We note that the word “minimize” was present in earlier drafts of the document. We are concerned about the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. This could lead to an incident where utilities are charged unreasonably? for example, for an outage from a tree that was one foot within the active ROW line. We should not be held liable when reasonable due diligence is practiced. Further, it is not economically feasible for utilities to survey every ROW in the U.S. and Canada to determine precise clearance zones.
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT. The SDT believes that the Transmission Owner holds responsibility for knowing the location of the edges of its active rights of way and whether a rooted tree is within or outside the active right of way.		
BCTC		BCTC strongly recommends that the requirement under R7 be changed from “shall prevent sustained outages” to “shall minimize sustained outages due to vegetation falling into a conductor.” We note that the

Organization	Agree?	Question 16 Comment
		word “minimize” was present in earlier drafts of the document. BCTC is concerned about the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW BCTC’s operating area covers rugged and remote terrain, and many areas have accessibility issues. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. Further, it is not economically feasible to accurately survey and marked on the ground the absolute width of all ROW in the province. Therefore, we are concerned about the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW. This could lead to an incident where BCTC is charged unreasonably – for example, for an outage from a tree that was one foot within the active ROW line. We should not be held liable when reasonable due diligence is practiced.
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT. The SDT believes that the Transmission Owner holds responsibility for knowing the location of the edges of its active rights of way and whether a rooted tree is within or outside the active right of way.		
Kansas City Power & Light	Disagree	Exceptions should include flying debris including vegetation.
Response: Thank you for your comment. Your suggestion has been incorporated.		
Associated Electric Cooperative Inc.	Disagree	Requirements 5, 6 and 7, as written, compel the Transmission Owner to allocate precious resources to ensuring a vegetation related outage will NEVER occur on any applicable transmission line, regardless of the line's true importance to maintaining electric transmission system reliability. All lines are not created equal; only those which are an IROL or contribute to IROLs should be held to a zero tolerance standard.
Response: Thank you for your comments. FERC Order 693 affirmed that the Standard shall apply to all transmission lines operating above 200kV as well as to designated sub-200kV lines. The Standard was prepared in accordance with FERC Order 693.		
NPCC	Disagree	NPCC participating members request clarification if violations of R5, R6, and R7 result in outages that must be reported.
Response: The SDT appreciates your response. Under NERC’s Compliance Guidelines, any violation of a reliability standard requirement must be self-reported; thus, a violation of Requirement R5, R6 or R7 must result in a report from the Transmission Owner.		
SERC OC Standards Review	Disagree	R5, R6 and R7 should begin with "Subject to its legal rights,”. The requirements, as written, compel the Transmission Operator to allocate precious resources to ensuring that a vegetation outage NEVER will occur

Organization	Agree?	Question 16 Comment
Group		on any transmission line, regardless of that line's true importance to maintaining electric transmission system reliability. All lines are not created equal; only those that are involved in IROLs should be held to a zero tolerance standard. R5, R6, and R7 ensure that version 2 of the standard has reliability requirements equal to version 1; therefore R4 should be removed.
Response: Thank you for your comments. **The SDT certainly agrees that all actions taken by a Transmission Owner must be within its legal rights, but believes that inclusion of "*Subject to its legal rights*" will tend to unnecessarily limit legitimate actions that a Transmission Owner must take to maintain reliability.** **FERC Order 693 affirmed that the Standard shall apply to all transmission lines operating above 200kV as well as to designated sub-200kV lines. The Standard was prepared in consideration of the directives and recommendations contained in FERC Order 693.**		
Florida Power & Light	Disagree	As currently written, Requirements R5, R6 and R7 demand perfection. The only acceptable number for all 150K miles of affected transmission line in the US is 0. The standard should be achievable and enable proactively addressing potential threats to facilities from vegetation. Even using a Six Sigma level of quality and control, processes can achieve a level of 3.4 defects per million opportunities for defect. Each tree on the ROW represents one of those opportunities. FPL has outlined an alternative proposal in response to Question 18.
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT.		
Santee Cooper	Disagree	Recommend removing R7 because current and proposed standards do not require the entire right-of-way or Active Transmission Line Right of Way to be clear of vegetation. In this case, a utility should not be penalized if a tree falls from within the right-of-way or Active Transmission Right-of-Way as long they are meeting all the other standards (e.g., minimum vegetation clearance distances). Since fall-ins from just outside of the right-of-way is currently not a compliance issue, it makes sense that a fall-in from within the right-of-way be treated the same. This is especially true for a utility who has elected to acquire a wider right-of-way than another utility. That utility may have a tree(s) growing just inside the right-of-way but still maintains a better clearance distance between trees and conductors than a utility with a narrower right-of-way and no tree encroachment.
Response: Thank you for your comments. While it is true that there is a negligible difference in risk to the electric system for trees just within or just outside the active right of way, the major difference is that the Transmission Owner generally has the right to manage vegetation within the active right of way. Also, while Transmission Owners employ differing active right-of-way widths, this is essentially uncontrollable by the SDT or by regulators.		

Organization	Agree?	Question 16 Comment
Exelon	Disagree	It appears to Exelon that the requirements of the standard have been written and modified at different times and as a result the document lacks a degree of consistency and coherence. While the Standard mentions encroachment of the CCZ and Sustained Outages as potential violations, it is completely silent on how momentary outages should be addressed. Exelon views the following events as a risk continuum that should be addressed in the Standard and handled as a part of the VRFs and VSLs - encroachment of the air gap distance, momentary outages and Sustained Outages.
Response: Thank you for your comments. The Minimum Vegetation Clearance Distance is the calculated spark-over distance derived from the Gallet equations. Therefore a momentary caused by a tree under the circumstances defined in R4 would by definition be a violation of R4.		
Platte River Power Authority	Disagree	The requirement under R7 should be changed from "shall prevent sustained outages" to "shall minimize sustained outages due to vegetation falling into a conductor." We note the word "minimize" was present in earlier drafts of the document. We are concerned about the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. This could lead to an incident where utilities are charged unreasonably - for example, for an outage from a tree that was one foot within the active ROW line. We should not be held liable when reasonable due diligence is practiced.
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT. The SDT believes that the Transmission Owner holds responsibility for knowing the location of the edges of its active rights of way and whether a rooted tree is within or outside the active right of way.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Disagree	I believe that the text for each element should be re-written with the general philosophy that the Transmission Owner shall do everything reasonable to prevent such problems in line with the comment for section 15.Problems should be reported and investigated and a judgment call should be made about whether the Transmission Owner did everything reasonable to avoid the problem.
Response: Thank you for your comments. The purpose of this standard is to improve reliability of the electric transmission system by preventing vegetation-related outages that can lead to cascading by establishing clear and measureable requirements. While the SDT appreciates the value of judgment in the field FERC has indicated that requirements in proposed Standards be equivalent to or more stringent than the same or similar requirements in already approved Standards.		
Consumers Energy Company	Disagree	R5, R6 and R7 should be rewritten as a single requirement for vegetation within the "Active Transmission Line Right of Way" and the exceptions listed. Additionally, a requirement for hazardous trees outside of the "Active

Organization	Agree?	Question 16 Comment
		Transmission Line Right of Way" should be incorporated into this draft and similar exceptions listed for natural disasters, third-party, and animal causes.
Response: Thank you for your comments. Requirements R5, R6 and R7 deal with three distinct types of outages which may pose different risks or severity in terms of impact to the electric system. The SDT chose to break the three requirements apart to allow application of different Violation Risk Factors because blow-in and fall-in interruptions do pose a significantly lower risk of causing a cascading blackout event. **Regarding incorporating a requirement to address hazardous trees outside the Active Right-of-Way, Transmission Owners generally have the right to manage vegetation within the Active Transmission Right-of- Way. These rights will not always exist beyond the Active Transmission Right-of-Way.**		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Disagree	We strongly recommend that the requirement under R7 be changed from “shall prevent sustained outages” to “shall minimize sustained outages due to vegetation falling into a conductor.” We note that the word “minimize” was present in earlier drafts of the document. We are concerned about the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. This could lead to an incident where utilities are charged unreasonably ? for example, for an outage from a tree that was one foot within the active ROW line. We should not be held liable when reasonable due diligence is practiced. Further, it is not economically feasible for utilities to survey every ROW in the U.S. and Canada to determine and document precise clearance zones. Such costly effort would not produce any benefit to the reliability of the bulk electric system.
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT. The SDT believes that the Transmission Owner holds responsibility for knowing the location of the edges of its active rights of way and whether a rooted tree is within or outside the active right of way.		
San Diego Gas & Electric	Disagree	We recommend that the requirement under R7 be changed from "shall prevent sustained outages" to "shall minimize sustained outages due to vegetation falling into a conductor." The word minimize was present in earlier drafts of the document. We are concerned with the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission Right of Way. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. This could lead to an incident where utilities are charged unreasonably.
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT. The SDT believes that the Transmission Owner holds responsibility for knowing the location of the edges of its active rights of way and whether a rooted tree is within or outside the active right of way.		

Organization	Agree?	Question 16 Comment
Hydro One Networks Inc.	Disagree	A further exception would be a sustained outage where the conductor has moved outside of the critical clearance zone. This could occur under conditions of heavy icing, operating outside the line rating or excessive wind. These would not necessarily be the result of a natural disaster. Also, it is recommended that the requirement for R7 be revised to "Each Transmission Owner shall minimize ("minimize" replacing "prevent") Sustained Outages of applicable lines due to vegetation falling into a conductor".. A fall in is a random occurrence and the likelihood that this would be the cause or contribute to a cascading event is very remote. These types of outages are rare and can be considered similar in nature to an insulator flashover or a hardware failure, which have not been given any association with cascading events. The purpose of the standard is to prevent cascading events and it is suggested that this remain the focus and not introduce other types of outages on a selective basis.
Response: Thank you for your comment. The Critical Clearance Zone (CCZ) has been removed from the standard. **The SDT concurs that fall in events present a lower risk to the system than grow in events. Requirements R5, R6 and R7 have been drafted to address three distinct types of outages which may pose different risks or severity in terms of impact to the electric system. The SDT chose to break the three requirements apart to allow application of different Violation Risk Factors and Violation Severity Levels.**		
Arizona Public Service Company	Disagree	APS strongly recommends that the requirement under R7 be changed from "shall prevent sustained outages" to "shall minimize sustained outages due to vegetation falling into a conductor." We note that the word "minimize" was present in earlier drafts of the document. We are concerned about the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. This could lead to an incident where utilities are charged unreasonably ? for example, for an outage from a tree that was one foot within the active ROW line. We should not be held liable when reasonable due diligence is practiced. Further, it is not economically feasible for utilities to survey every ROW in the U.S. and Canada to determine precise clearance zones.
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT. The SDT believes that the Transmission Owner holds responsibility for knowing the location of the edges of its active rights of way and whether a rooted tree is within or outside the active right of way.		
Entergy Services	Disagree	1. If a version of R4 that states an encroachment to the Critical Clearance Zone is a violation, Entergy disagrees with the need for R5, R6, and R7 because it is redundant to R4. An outage cause by vegetation: a) growing into the line b) blowing into the line and c) falling into the conductor would require the vegetation to break the Critical Clearance Zone. If these requirements stay in the standard, an outage of the above nature would mean the entity violated two requirements, R4 and R5, R6, or R7. 2. Entergy is amenable to keeping

Organization	Agree?	Question 16 Comment
		R5, 6, and 7 if R4 is removed from the standard. 3. If approved, we suggest that R5, 6, and 7 not apply to trees from off the right of way.
Response: Thank you for your comments. Requirements R5, R6 and R7 have been drafted to address three distinct types of outages which may pose different risks or severity in terms of impact to the electric system. The SDT chose to break the requirements apart to allow application of different Violation Risk Factors and Violation Severity Levels. R4 has been drafted to clarify that clearance encroachments are violations of the Standard. Matters of being assessed two violations for a single event are addressed in the NERC compliance sanctions guideline.		
Salt River Project	Disagree	Recommend that the requirement under R7 be changed from "shall prevent sustained outages" to "shall minimize sustained outages due to vegetation falling into a conductor". We understand that the word "minimize" was present in earlier drafts of the document. We are concerned about the requirement to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. This could lead to an incident where a utility is charged unreasonably - for example, for an outage from a tree that was one foot within the active ROW line. We should not be held liable when reasonable due diligence is practiced. Furthermore, it is not economically feasible for utilities to survey every ROW to determine precise clearance zones.
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT. The SDT believes that the Transmission Owner holds responsibility for knowing the location of the edges of its active rights of way and whether a rooted tree is within or outside the active right of way.		
Hydro-Quebec Transenergie (HQT)	Disagree	HQT request clarification if violations of R5, R6, and R7 result in outages that must be reported. A further exception would be a sustained outage where the conductor has moved outside the critical clearance zone. This could occur under conditions of heavy icing, operating outside the line rating or excessive wind.
Response: Thank you for your comments. Regarding your question on reporting of violations, under NERC's Compliance Guidelines, any violation of a reliability standard requirement must be self-reported; thus, a violation of Requirement R5, R6 or R7 must result in a report from the Transmission Owner. In addition, the revised standard includes compliance elements, including the need to provide periodic reports of specific vegetation-related outages. **The Critical Clearance Zone (CCZ) is defined by the movement of the conductor between no load and its rating. The Standard does not apply to events which occur outside of the CCZ.**		
Southern California Edison	Agree	Q16: SCE agrees in part with the establishment of R5, R6 and R7, however, we note that the opening of each requirement repeats a slightly altered version of the FAC-002-2 purpose statement. We find such

Organization	Agree?	Question 16 Comment
Company		repetitiveness unnecessary and note that as written, Requirements 5-7 presents a near identical compliance conundrum for Transmission Owners as Requirement 4. Again, Transmission Owners would be required to prove that they did not incur a sustained outage due to a vegetation caused flash-over or vegetation-to-line contact whether it be a grow-in, blow-in or fall-in. Although proving a sustained outage (for cause) did not occur will be difficult and unwieldy, it is not impossible. The simple difference between a Transmission Owner disproving the occurrence of a CCZ incursion and their disproving vegetation caused sustained outages, is that Transmission Owners do in fact keep records of “outages”. Because a Transmission Owner’s record keeping prowess is the only viable option for proving a vegetation caused outage did not occur, SCE respectfully suggests R5, R6 and R7 be revised to read:R5 - "Each Transmission Owner shall document Sustained Outages of applicable lines due to vegetation growing into a conductor operating within its Rating with the following exceptions:"R6 - "Each Transmission Owner shall document Sustained Outages of applicable lines due to vegetation blowing into a conductor operating within its Rating and located within an Active Transmission Line Right of Way with the following exceptions:"R7 - "Each Transmission Owner shall document Sustained Outages of applicable lines due to vegetation falling into a conductor operating within its Rating and located within an Active Transmission Line Right of Way with the following exceptions: "We also note that Footnote 6 is misplaced in the draft and should follow the word “Outages” in each of these requirements.
Response: Thank you for your comments. Requirements R5, R6 and R7 deal with three distinct types of outages which may pose different risks or severity in terms of impact to the electric system. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Additionally, the Transmission Owner must document and report outages under NERC’s Compliance Guidelines. However, the SDT chose to break the three requirements apart to allow application of different Violation Risk Factors and Violation Severity Levels. **As to the matter of proving the lack of CCZ incursions, please refer to the SDT’s response to your Question # 15 comments.** **Your suggestion regarding Footnote 6 has been incorporated.**		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 16.
Response: Thank you for your comments.		
American Electric Power (AEP)	Agree	AEP is in agreement with these changes.
Response: Thank you for your supportive comment.		
City of Tallahassee	Agree	Why have we gone backwards with only "Sustained Outages" being a violation? Even a momentary outage indicates that a violation has occurred if the cause was vegetation related (with the same exceptions). This

<table>
<tr><th>Organization</th><th>Agree?</th><th>Question 16 Comment</th></tr>
<tr><td></td><td></td><td>would seem to contradict the proposed R4. If it wasn't a Sustained Outage it wasn't a violation? If you have a sustained outage due to vegetation, you must have violated the CCZ.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The SDT very carefully and thoroughly examined the merits, disadvantages, ease and difficulties of assessing momentary outages as a violation. The result of that effort led to the more precise and field observable aspects of R4. It should be noted that by their very nature the exact causes of “momentary outages” are very challenging to determine and will vary widely from utility to utility. The SDT did not find that such variability was appropriate for a reliability standard, and chose to address this issue with the language in R4.</td></tr>
<tr><td>Northern Indiana Public Service Company</td><td>Agree</td><td>While being more specific & explicit, I don't interpret the overall requirement as being any different from the current standard.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. Please note that while the current standard did not specifically define an interruption as a violation, the proposed standard explicitly defines outages as violations.</td></tr>
<tr><td>Orange and Rockland Utilities Inc.</td><td>Agree</td><td>We agree, but recommend that momentary outages be included as violations of all three requirements as well. Also, the Standard does not directly require reporting of vegetation-related outages although implicitly, outages which are violations of the Standard must be reported. This has lead to some confusion during this comment phase and we suggest that the reporting requirements be directly stated in the Standard.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. Under the Compliance section of the new standard section 2 the Transmission Owner is required to report outages.</td></tr>
<tr><td>Xcel Energy</td><td>Agree</td><td>We agree, however please add a reference to ?wind gusts 45 miles per hour or greater? to the exception note for this requirement. The exception would read ?1) Sustained Outages of transmission lines that result from sustained winds (45 miles per hour or greater) or gusts due to natural disasters.?</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The SDT believes that a fresh gale (see footnote 4) represents an appropriate threshold for exemptions.</td></tr>
<tr><td>Manitoba Hydro</td><td>Agree</td><td>Agree with splitting the various events. We note that there is no specific requirement to actually report an outage. The Requirements say that we should Prevent Sustained Outages, but not actually report sustained outages should they occur. In version 1, R3 clearly stated that the Transmission Owner shall report.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. Under NERC’s Compliance Guidelines, any violation of a reliability standard requirement must be self-reported; thus, a violation of Requirement R5, R6 or R7 must result in a report from the Transmission Owner.</td></tr>
</table>

Organization	Agree?	Question 16 Comment
National Grid	Agree	National Grid agrees with the proposed change, however, Standard FAC-003-2 does not provide outage reporting requirements in R5, R6, R7, or anywhere else in the Standard.
Response: Thank you for your comments. Under NERC's Compliance Guidelines, any violation of a reliability standard requirement must be self-reported; thus, a violation of Requirement R5, R6 or R7 must result in a report from the Transmission Owner. The revised standard includes compliance elements, including the need to provide periodic reports of specific vegetation-related outages.		
Pacific Gas & Electric Co.	Agree	M5, M6 and M7 do not explicitly exclude the exceptions in R5, R6 and R7 and should do so.
Response: Thank you for your comments. The SDT believes that the requirements and measures are properly aligned. The exceptions language is appropriately located in the technical requirement.		
Consolidated Edison Company of New York (CECONY)	Agree	CECONY agrees that outages caused by the factors mentioned are violations of R5, R6, and R7 but we recommend that either the phrase 'momentary outage' be included in the wording or the phrase 'All Outages' replace 'Sustained Outages' to make the requirements clearer.
Response: Thank you for your comments. The SDT very carefully and thoroughly examined the merits, disadvantages, ease and difficulties of assessing momentary outages as a violation. The result of that effort led to the more precise and field observable aspects of R4. It should be noted that by their very nature the exact causes of "momentary outages" are very challenging to determine and will vary widely from utility to utility. The SDT did not find that such variability was appropriate for a reliability standard, and chose to address this issue with the language in R4.		
WECC	Agree	However reporting requirements are not identified in the standard. WECC believes that sustained outages caused by vegetation should be reported to the Regional Entity using the existing reporting requirements in FAC-003-1
Response: Thank you for your comments. Under NERC's Compliance Guidelines, any violation of a reliability standard requirement must be self-reported; thus, a violation of Requirement R5, R6 or R7 must result in a report from the Transmission Owner. The revised standard includes compliance elements, including the need to provide periodic reports of specific vegetation-related outages.		
CenterPoint Energy	Agree	We agree with the exemptions; however, R6 and R7 refer to an "Active Transmission Line Right-of-way" which is not defined as to its limits, so M6 and M7 cannot be determined by definition. See comments to Q3 above relating to the definitions and the examples in the Technical Reference.
Response: Thank you for your comments. The SDT asserts that the Transmission Owner is responsible for defining the Active Transmission Line Right of Way. Additionally please refer to the response to Question 3. Note that the SDT made significant changes to clarify R5, R6 and R7 and the associated		

Organization	Agree?	Question 16 Comment
measures.		
Pepco Holdings, Inc	Agree	There is no need for three separate requirements if the incident is a Sustained Outage, but there is nothing inherently wrong with the three requirements.
Response: Thank you for your comments. Requirements R5, R6 and R7 have been drafted to address three distinct types of outages which may pose different risks or severity in terms of impact to the electric system. The SDT chose to break the requirements apart to allow application of different Violation Risk Factors and Violation Severity Levels.		
Northeast Utilities	Agree	Agree that contacts resulting in sustained outages due to vegetation from within the active transmission line right-of-way should constitute a violation of the Standard. However, this Standard is written for a zero tolerance of any vegetation caused outages or encroachment into the CCZ. One vegetation-caused outage or one CCZ encroachment may not result in a potential Cascading effect. Agree with the use of different violation risk factors (VRF's) and violation severity levels (VSL's) for each of the three outage classes. Also - how are outage violations to be reported - there is no provision in the revision for the reporting process and requirements (specifics on the type of violation). Will this be addressed in the Compliance Section yet to be added? Suggest in both R6 and R7, move the phrase "within an Active Transmission Line Right of Way" to immediately follow "vegetation".
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT. **Requirements R5, R6 and R7 have been drafted to address three distinct types of outages which may pose different risks or severity in terms of impact to the electric system. The SDT chose to break the requirements apart to allow application of different Violation Risk Factors and Violation Severity Levels.** **Regarding your question on reporting of violations, under NERC's Compliance Guidelines, any violation of a reliability standard requirement must be self-reported; thus, a violation of Requirement R5, R6 or R7 must result in a report from the Transmission Owner. In addition, the revised standard includes compliance elements, including the need to provide periodic reports of specific vegetation-related outages.** **Your suggested wording change to requirements R6 and R7 was evaluated by the SDT. The SDT asserts that the original wording is appropriate.**		
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	

Organization	Agree?	Question 16 Comment
Northern California Power Agency (NCPA)	Agree	
Central Maine Power Company	Agree	
Tampa Electric Company	Agree	
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
SERC Vegetation Management Subcommittee (VMS)	Agree	
Progress Energy Florida	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Progress Energy Carolinas	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
Bonneville Power Administration	Agree	
FirstEnergy	Agree	
MRO NERC Standards Review Subcommittee	Agree	

Organization	Agree?	Question 16 Comment
Midwest ISO Stakeholders Standards Collaborators	Agree	
Ameren	Agree	
American Transmission Company	Agree	
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Edison Electric Institute	Agree	
Baltimore Gas & Electric Company	Agree	
Duke Energy Corporation	Agree	
JEA	Agree	
Independent Electricity System Operator	Agree	
Buckeye Power, Inc.	Agree	
Great River Energy	Agree	

17. R8 is a new requirement which separates the implementation of the annual plan from the requirement to have an annual plan. Do you agree with R8? If not please explain.

Summary Consideration: The SDT modified the Requirement for implementation of the work plan (now R9 in the revised standard) after reviewing these comments. Commenters focused on two main areas. First, there was a suggestion that the work plan wording be amended to include a note that it was only required on the Active Right of Way. Requirement R1 clearly limits the scope of the TVMP to work on the entity's Active Transmission Line Rights of Way - and the "annual work plan" is one element of the overall TVMP. The second overriding theme was that the standard be re-ordered to better tie the requirement to have a plan and the requirement to implement a plan. Some commenters suggested that the requirement to implement the annual work plan be embedded as part of Requirement R1, and the SDT did not make this change. The requirement to "have" a TVMP is administrative and the requirement to "implement" the annual work plan is a real-time requirement – by keeping these requirements separate, each requirement can be assigned an appropriate VRF. The SDT is offering for comment a proposed re-ordering of the Standard that provides a more logical sequence to the Standard which, if supported by stakeholders, can be applied to Draft 3 of the standard.

For Draft 2, the SDT also removed the wording "within the extent of its easements and/or legal rights." The justification for removing these words was to remove the possibility that the TO would be held to the maximum criteria or be limited to the minimum criteria outlined in their easements.

R9. Each Transmission Owner shall implement its annual work plan for vegetation management to accomplish the purpose of this standard.

Deleted: R8

Deleted: within the extent of its easement and/or legal rights

Organization	Agree?	Question 17 Comment
Central Maine Power Company		Central Maine Power Company suggests that R9 read as A Transmission Owner shall implement its annual work plan within the Active Right of Way to the the extent of its easements or legal rights.
Response: The SDT thanks you for your response. In response to overwhelming industry comments The SDT has removed the words "within the extent of its easements and/or legal rights". The SDT also feels that the Active Right of Way concept is supported adequately in Requirement R1 which limits the scope of the TVMP (and the annual work plan) to the entity's Active Rights of Way.		
British Columbia Transmission Corp		BCTC understands that it's possible to have an annual plan and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the plan is kept together with the requirement to implement it.
Response: The SDT thanks you for your response. The SDT proposes a new sequence for the technical Requirements R1-R11 and seeks industry feedback as requested in Question 4 of the Second Comment Form.		

Organization	Agree?	Question 17 Comment
Western Utility Arborists		The Western Utilities understands that it's possible to have an annual plan and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the plan is kept together with the requirement to implement it.
Response: The SDT thanks you for your response. The SDT proposes a new sequence for the technical Requirements R1-R11 and seeks industry feedback as requested in Question 4 of the Second Comment Form.		
SERC Vegetation Management Subcommittee (VMS)	Disagree	While the SERC VMS agrees in principle, we believe that the Requirement, as written, is "open ended" and could be interpreted to be in conflict with the "Active Rights of Way" concept. Clarifying the intent for the annual plan to focus on the Active Rights of Way will prevent incorrect interpretations. The SERC VMS suggest that the Requirement be reworded to read: ?Each Transmission Owner shall implement its annual work plan for vegetation management within the Active Right of Way to accomplish the purpose of this standard within the extent of its easements and or legal rights.?
Response: The SDT thanks you for your response. The SDT considered your request at length but feels that the Active Right of Way concept is supported adequately in Requirement R1 which limits the scope of the TVMP (and the annual work plan) to the entity's Active Rights of Way.		
JEA	Disagree	See comment from #3.
Response: Thank you for your comment. Please see the response to comments on #3. .		
Salt River Project	Disagree	The document would be easier to follow if the two elements would be kept together in the same requirement (similar to comments in #4, #6, & #14 above). It makes the standard longer than necessary and creates redundancy.
Response: The SDT thanks you for your response. The reason that the development of the annual plan and the implementation of the plan were separated was to apply the appropriate VRF's and VSL's to each. The SDT feels that the current organization is appropriate because development of the annual work plan is a sub-part of the development of the Transmission Vegetation Management Program and should be separate from the implementation requirement for the annual plan.		
SERC OC Standards Review Group	Disagree	The SERC OCSRG suggests that the Requirement be reworded to read: "Each Transmission Owner shall implement its annual work plan for vegetation management within the Active Rights of Way." Any further verbiage is confusing, ambiguous or unnecessary.
Response: The SDT thanks you for your response. The SDT considered your request at length but feels that the Active Right of Way concept is supported adequately in the definition and elsewhere in the standard. The SDT did, however, remove the last phrase of the sentence, "within the extent		

Organization	Agree?	Question 17 Comment
of its easement and/or legal rights."		
Florida Power & Light	Disagree	The standard goes to great length to specify the Active Transmission Right-of-Way but omits its reference in requirement R9. The inclusion of this term in Requirement R9 adds consistency to the application of the standard. FPL suggests the following change: "Each Transmission Owner shall implement its annual work plan for vegetation management to accomplish the purpose of this standard within the extent of its easement and/or legal rights in the Active Transmission Line Right-of-Way."
Response: The SDT thanks you for your response. Due to industry comments the SDT revised the wording on this requirement to delete the words "within the extent of its easements and/or legal rights". The SDT also feels that the Active Right of Way concept is supported adequately in the Requirement R1 which limits the scope of the TVMP (and the annual work plan) to the entity's Active Rights of Way.		
Southern Company	Disagree	While we agree in principle, we feel Requirement R9 as written is "open ended" and could be interpreted to be in conflict with the "Active Rights of Way" concept. Clarifying the intent for the annual plan to focus on the Active Rights of Way will prevent incorrect interpretations. We suggest that the Requirement be reworded to read: Each Transmission Owner shall implement its annual work plan for vegetation management within the Active Right of Way to accomplish the purpose of this standard within the extent of its easements and or legal rights.
Response: The SDT thanks you for your response. Due to industry comments the SDT revised the wording on this requirement to delete the words "within the extent of its easements and/or legal rights". The SDT also feels that the Active Right of Way concept is supported adequately in Requirement R1 which limits the scope of the TVMP (and the annual work plan) to the entity's Active Rights of Way.		
E.ON U.S.	Disagree	E.ON U.S. believes that the Requirement, as written, is "open ended" and could be interpreted to be in conflict with the "Active Rights of Way" concept. Clarifying the intent for the annual plan to focus on the Active Rights of Way will prevent incorrect interpretations. We suggest that the Requirement be reworded to read: "Each Transmission Owner shall implement its annual work plan for vegetation management within the Active Right of Way to accomplish the purpose of this standard within the extent of its easements and or legal rights."
Response: The SDT thanks you for your response. The SDT agrees with your comments and has removed the words "within the extent of its easements and/or legal rights". The SDT also feels that the Active Right of Way concept is supported adequately in Requirement R1 which limits the scope of the TVMP (and the annual work plan) to the entity's Active Rights of Way.		
Exelon	Disagree	Strike "within the extent of it's easement and / or legal rights." This is unnecessary and will cause confusion. The annual work plan as required to be developed per R1.3 requires consideration of permitting, scheduling and regulatory limitations.

Organization	Agree?	Question 17 Comment
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support for your suggestion and the requirement has been revised to reflect your suggestion.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Disagree	We understand that it is possible to have an annual plan and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the plan is kept together with the requirement to implement it.
Response: The SDT thanks you for your response. The SDT feels that the current organization is appropriate because development of the annual work plan is a sub-part of the development of the Transmission Vegetation Management Program and should be separate from the implementation requirement for the annual plan. The SDT proposes a new sequence for the technical Requirements R1-R11 and seeks industry feedback as requested in Question 4 of the Second Comment Form.		
San Diego Gas & Electric	Disagree	We feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the plan is kept together with the requirement to implement the plan.
Response: The SDT thanks you for your response. The SDT feels that the current organization is appropriate because development of the annual work plan is a sub-part of the development of the Transmission Vegetation Management Program and should be separate from the implementation requirement for the annual plan. The SDT proposes a new sequence for the technical Requirements R1-R11 and seeks industry feedback as requested in Question 4 of the Second Comment Form.		
Baltimore Gas & Electric Company	Disagree	As in question no. 14 above for R1.2, it would seem to make more sense to combine R1.3 & R9 as follows: "Require development and implementation of an annual plan that?."
Response: The SDT thanks you for your response. The reason that the development of the annual plan and the implementation of the plan were separated was to apply the appropriate VRF's and VSL's to each. The SDT feels that the current organization is appropriate because development of the annual work plan is a sub-part of the development of the Transmission Vegetation Management Program and should be separate from the implementation requirement for the annual plan.		
Pepco Holdings, Inc	Disagree	THE SDT has introduced the term Active Transmission Line Right of Way. R9 should use this term to avoid any misinterpretation.
Response: The SDT thanks you for your response. In response to industry comments The SDT has removed the words "within the extent of its easements and/or legal rights". The SDT also feels that the Active Right of Way concept is supported adequately in Requirement R1 which limits the scope of the TVMP (and the annual work plan) to the entity's Active Rights of Way.		

Organization	Agree?	Question 17 Comment
Great River Energy	Disagree	GRE both Agrees and Disagrees. GRE agrees with the separation between having an annual plan and implementing it. However, GRE suggests removing all the words after vegetation management.
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support for your suggestion and the requirement has been revised to reflect your suggestion.		
City of Tallahassee	Disagree	Combined with Question 6. R9 needs to have the same flexibility that R1.3 has. As written, it could be argued that you have to do everything in your annual plan, AND anything in addition due to the changing conditions. This contradicts what is put forth in the white paper. I would add "as modified per R1.3" after "implement it's annual work plan for vegetation management"
Response: The SDT thanks you for your response. The SDT feels that the "flexibility" of the annual plan is built into the development of the plan and that same flexibility carries through to the implementation.		
Tampa Electric Company	Disagree	Good start. R9 must also address the flexibility which is addressed in R1.3. As written, R9 does not do this. In addition, R9 states "within the extent of its easement and/or legal right..". This could create another set of conflicting criteria, where the utility has a long term "interim corrective action plan".
Response: The SDT thanks you for your response. The SDT feels that the "flexibility" of the annual plan is built into the development of the plan and that same flexibility carries through to the implementation. The SDT does agree with the possible confusion the words "within the extent of its easement and/or legal rights" could cause and has consequently removed these words from the requirement.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Disagree	This standard needs to be broadened to include evaluation of the good faith efforts by the Transmission Owner to coordinate with the USFS on development of the work plan. A mechanism should be developed to allow the Transmission Owner to evaluate the good faith efforts of the USFS.
Response: The SDT thanks you for your response. The Standard is a continental reliability standard. While the SDT agrees with you that every Transmission Owner should strive for mutually beneficial relationships with the various landowners and other entities involved in vegetation management, it would be outside the purvey of this effort to outline specific relationships.		
Arizona Public Service Company	Disagree	APS understands that it's possible to have an annual plan and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the plan is kept together with the requirement to implement it.
Response: The SDT thanks you for your response. The SDT feels that the current organization is appropriate because development of the annual work plan is a sub-part of the development of the Transmission Vegetation Management Program and should be separate from the implementation		

Organization	Agree?	Question 17 Comment
requirement for the annual plan. The SDT proposes a new sequence for the technical Requirements R1-R11 and seeks industry feedback as requested in Question 4 of the Second Comment Form.		
SERC Compliance Staff	Agree	Vegetation management practices should be extended areas outside of the active rights-of-way (ROW) to the extent necessary to prevent vegetation-related outages. This should include the identification and removal of trees that could impact transmission line operation similar to the practice of identifying danger trees off of the ROW. The requirement as written could serve to reward those entities that, for whatever reason, have insufficient right-of-way widths. From a practical perspective, it should not be necessary to perform clear cutting of non-active ROW, but Entities should be held responsible for any outages that occur due to contact with vegetation within their legal rights to control.
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support to remove any wording referring to the easement rights. The SDT agreed with this view and has revised the requirement.		
ITC HOLDINGS	Agree	Clarifying the intent for the annual plan is to focus on the Active Rights of Way will prevent interpretation conflicts
Response: The SDT thanks you for your response. The SDT agrees with your observation, but also points out that the requirement for an annual work plan (sub-part 1.3) is part of Requirement R1, which specifically states its applicability to Active Transmission Line Rights of Way. Therefore, the SDT respectfully feels that your concern is addressed without additionally placing such verbiage in R8 (now R9).		
American Electric Power (AEP)	Agree	AEP agrees with this change.
Response: The SDT thanks you for your comments. The SDT modified the requirement, based on stakeholder comments, to remove the last phrase, "within the extent of its easement and/or legal rights."		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 17
Response: The SDT thanks you for your comment. The SDT modified the requirement, based on stakeholder comments, to remove the last phrase, "within the extent of its easement and/or legal rights."		
Platte River Power Authority	Agree	The separation allows lower sanctions and penalties to be assessed for a weak plan and higher sanctions and penalties to be assessed for not implementing an annual plan. However, we feel that the standard itself would be easier to follow if it was re-organized so that the requirement to have a plan is kept together with the requirement to implement it.

Organization	Agree?	Question 17 Comment
Response: The SDT thanks you for your response. The reason that the development of the annual plan and the implementation of the plan were separated was to apply the appropriate VRF's and VSL's to each. The SDT feels that the current organization is appropriate because development of the annual work plan is a sub-part of the development of the Transmission Vegetation Management Program and should be separate from the implementation requirement for the annual plan. The SDT proposes a new sequence for the technical Requirements R1-R11 and seeks industry feedback as requested in Question 4 of the Second Comment Form.		
American Transmission Company	Agree	ATC agrees with the requirement to implement the annual work plan, but recommends striking the words "within the extent of its easement and/or legal rights". The emphasis for this requirement is to execute the annual work plan. The white paper already speaks to the point that it is a best practice for utilities to exercise their legal rights. If we agree that the goal is to prevent outages, then we can simply end this requirement with "implement its annual work plan for vegetation management." Propose Changes to R9: Each Transmission Owner shall implement its annual work plan for vegetation management.
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support for your suggestion and the requirement has been revised to reflect your suggestion.		
Ameren	Agree	We recommend striking, or modifying, the words "within the extent of its easement and/or legal rights" as they may be introducing an unintended compliance quagmire. For example, if the easement is extraordinarily wide but reliability and the work plan do not dictate that the work plan apply to the entire easement, how will compliance be measured? The work plan should recognize easement or legal rights issue. Therefore, the emphasis for this requirement should be to execute the annual work plan. The white paper already speaks to the point that it is a best practice for utilities to exercise their legal rights. By tagging the words on to the requirement, we are adding unnecessary compliance validation to this requirement for both industry and the regulators. If a clarifying sentence is required, we would suggest that R9 stop with the word standard and a new sentence be added, "The work plan should address easement or legal/rights"
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support for your suggestion and the requirement has been revised to reflect your suggestion.		
MRO NERC Standards Review Subcommittee	Agree	The MRO both Agrees and Disagrees. The MRO agrees with the separation between having an annual plan and implementing it. However, the MRO suggests removing all the words after vegetation management.
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support for your suggestion and the requirement has been revised to reflect your suggestion.		

Organization	Agree?	Question 17 Comment
Midwest ISO Stakeholders Standards Collaborators	Agree	We recommend striking the words "within the extent of its easement and/or legal rights". The emphasis for this requirement is to execute the annual work plan. The white paper already speaks to the point that it is a best practice for utilities to exercise their legal rights. By tagging the words on to the requirement, we are adding unnecessary compliance validation to this requirement for both industry and the regulators. By the way this is written, it could be interpreted different ways. If we agree that the goal is to prevent outages, then we can simply end this requirement with "accomplish the purpose of the standard". Each Transmission Owner would be accountable to manage compliance with this standard and public relations in their service area.
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support for your suggestion and the requirement has been revised to reflect your suggestion.		
Duke Energy Corporation	Agree	Duke agrees with the requirement to implement the annual work plan, but recommends striking the words "within the extent of its easement and/or legal rights". The emphasis for this requirement is to execute the annual work plan. The white paper already speaks to the point that it is a best practice for utilities to exercise their legal rights. If we agree that the goal is to prevent outages, then we can simply end this requirement with "accomplish the purpose of the standard". Each Transmission Owner will be accountable to manage compliance with this standard.
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support for your suggestion and the requirement has been revised to reflect your suggestion.		
CenterPoint Energy	Agree	R9 requires implementation of the annual work plan "within the extent of its [the Transmission Owner's] easement and/or legal rights." All measures and compliance should be determined on this basis as well. This concept should also be carried through the definitions for "Active Transmission Line Right-of-way" and "Critical Clearance Zone", or for any definition of clearances should the Standard continue to utilize such terms.
Response: The SDT thanks you for your response. In response to industry comments The SDT has removed the words “within the extent of its easements and/or legal rights”. The SDT also feels that the Active Right of Way concept is supported adequately in the definition and in Requirement R1 which limits the scope of the TVMP (and the annual work plan) to the entity’s Active Rights of Way.		
Progress Energy Florida	Agree	While Progress Energy agrees with the change, the term “annual plan” should be a defined term including threshold elements.
Response: The SDT thanks you for your response. The SDT feels that the annual plan is adequately defined between the descriptions in the Standard (sub section 1.3) and in the technical reference document.		

Organization	Agree?	Question 17 Comment
Southern California Edison Company	Agree	Q17: SCE agrees in part with the inclusion of R9, however, we believe R9 should be revised and renumbered to replace proposed R3. In SCE's view, the act of implementing a Transmission VM program encompasses both inspection and maintenance activities. SCE respectfully suggests that proposed R9 be revised to read: "Each Transmission Owner shall implement and follow its Vegetation Management Program to the extent allowed by existing easement and/or legal rights."
Response: The SDT thanks you for your response. The SDT separates the vegetation inspections from the annual work plan because of partly due to the fundamental importance of the inspection process, and partly because a key purpose of an inspection is to provide input to the formation of the annual work plan. The SDT also points out that the TVMP is comprises the overarching processes and standards for program management, while the annual plan is the specific annual activities to accomplish the goals set forth in the program. In addition, the SDT modified the requirement, based on many other stakeholder comments, to remove the last phrase, "within the extent of its easement and/or legal rights."		
FirstEnergy	Agree	FirstEnergy agrees with the intent of R9, but the standard should be clarified by removal of the word "easement". As written the standard is open to interpretation between "easement" and active right of way. It is important to have the term "legal rights" remain in the standard. The Transmission Owner should be held accountable to fully enforce the legal rights outlined in maintaining the active right of way. This will lead to a more reliable transmission system.
Response: The SDT thanks you for your response. Due to industry comments the SDT revised the wording on this requirement to delete the words "within the extent of its easements and/or legal rights". While we agree and state in the technical reference document that clearing to the maximum extent is in most cases the best practice, there are particular situations where a clear cut policy would not be in the best interest of the Transmission Owner or the landowner. The SDT also feels that the Active Right of Way concept is supported adequately in Requirement R1 which limits the scope of the TVMP (and the annual work plan) to the entity's Active Rights of Way.		
Pacific Gas & Electric Co.	Agree	PG&E agrees with the requirement to implement the annual work plan, but recommends removing the language "within the extent of its easement and/or legal rights".
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support for your suggestion and the requirement has been revised to reflect your suggestion.		
Entergy Services	Agree	Entergy would like to note that requirements R1.3 and R9 are administrative requirements that add marginal value to the reliability of the Transmission System. Since entities are required to have flexible annual plans, deviations from the annual plan only need to be documented and these requirements will be met. Entergy utilizes annual plans as a good practice but sees limited value with the inclusion in this standard.
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad concern that the current wording could		

Organization	Agree?	Question 17 Comment
cause confusion with the wording "within the extent of its easements and/or legal rights". Consequently the SDT agreed with this view and has revised the requirement to address these concerns. The SDT respectfully disagrees that sub section 1.3 and R9 are administrative requirements and only add marginal value to the reliability of the system. Requirement R8 (now R9) is a real-time requirement, not an administrative requirement.		
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Northern California Power Agency (NCPA)	Agree	
Northern Indiana Public Service Company	Agree	
Bonneville Power Administration	Agree	
Orange and Rockland Utilities Inc.	Agree	
Manitoba Hydro	Agree	
Consumers Energy Company	Agree	
National Grid	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Independent Electricity System	Agree	

Organization	Agree?	Question 17 Comment
Operator		
Northeast Utilities	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
Buckeye Power, Inc.	Agree	
Santee Cooper	Agree	
Associated Electric Cooperative Inc.	Agree	
NPCC	Agree	
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Progress Energy Carolinas	Agree	
Response: Thank you for your positive response. The SDT modified the requirement, based on many other stakeholder comments, to remove the last phrase, "within the extent of its easement and/or legal rights."		

18. If you have further suggestions for improving this standard or the technical reference document, please offer them.

Summary Consideration: The overall industry feedback provided to this question reiterated concerns expressed in previous comments above. Most were related to the Critical Clearance Zone and associated issues of measurability, enforceability and practicality.

<table>
<tr><th>Organization</th><th>Question 18 Comment</th></tr>
<tr><td>Associated Electric Cooperative Inc.</td><td>R10 and R11: Associated Electric Cooperative Inc does not believe the Reliability Coordinator (RC) is the appropriate entity to determine whether or not selected sub-200 kv transmission lines should be subject to this standard. The planning horizon for the RC is typically much shorter than the time needed to incorporate a sub-200 kv transmission line into a vegetation management program. Associated recommends Planning Coordinator be designated as the applicable functional entity and be substituted wherever Reliability Coordinator appears in the Standard.

M1.4: The language in M1.4, requiring immediate communication of an imminent threat to the Transmission Operator, is inconsistent with the Applicability in Section A.4.1.1 which designates the Transmission Owner as the responsible entity.

M4: The preparation and retention of inspection reports, imminent threat reports, quality assurance reports, etc. is appropriate. These reports would not, however, absolutely demonstrate the Transmission Owner had experienced no vegetation encroachments into the Critical Clearance Zone. A negative cannot be proven.

M6 and M7: The Transmission Owner is again expected to demonstrate a negative to prove compliance.

Section C: Associated Electric Cooperative Inc recognizes the Standard, as posted, is a first draft for comments and will likely be revised before submittal for ballot. However, the Compliance section should be posted for an adequate comment period prior to balloting.</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments.

The drafting team has made significant changes to the draft standard in response to industry comments, including the replacement of RC with PC.

R1.4 and M1.4 are changed and the inconsistency has been resolved.

R4 and M4 are changed such that real time observations during inspections and patrols replace the previous condition of proving a negative. In addition, the revised standard does not use the concept of the Critical Clearance Zone.

M6 and M7 have been changed so that the proof of a negative is not required.

The SDT had developed compliance elements for the industry to review in the second comment period.</td></tr>
<tr><td>NPCC</td><td>NPCC requests that the Standard Drafting Team review the compliance and reporting requirements for consistency and adequacy.</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Question 18 Comment</th></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments. The drafting team has made significant changes to the draft standard in response to industry comments. Compliance elements have been added to the second draft of the standard.</td></tr>
<tr><td>WECC Reliability Coordination</td><td>R10 Should a dispute arise, how are those disputes resolved. Who keeps the list.

R10 What is acceptable methodology given the lack of interpretation of unacceptable risk of instability(R 10.2) or cascading failures. There is no definition of the consequences if a sub 200kv line is left off the list for vegetation management, and caused a cascading outage or placed the grid at an unacceptable risk of instability.</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments The drafting team has made significant changes to the draft standard in response to industry comments.

The RC has been replaced with the PC in R9 and R10.

This standard requires the PC to prepare and keep the list. Requiring the list to be developed in consultation with the TO ensures that the list will be available to the TO for the purposes in this Standard. The revised language should eliminate any disputes as the PC is ultimately the responsible entity for developing the list.

R10 was revised and now uses terminology that replicates terms within the IROL definition in the NERC Glossary of Terms for reliability standards. The intent is for the PC to use the same methods that determine those lines which are elements of an IROL be used to determine sub 200kV lines which are applicable to this standard.

While the planning study or similar analysis as cited in M10 could contain errors, it is not the intent of this standard to determine the competency of the PC or the results of PC any PC's analysis.</td></tr>
<tr><td>Western Area Power Administration, Upper Great Plains Region</td><td>1) Proactive utilities are implementing policies that call for the removal of all vegetation that could grow into the Critical Clearance Zone . Such policies are not without resistance from landowners, environmental groups, etc. One of the arguments used by such groups is that NERC/FERC do not require removal of the trees. It would very helpful if this document included the practice of removing vegetation capable of encroaching within the Critical Clearance Zone   as a reasonable or acceptable practice under this Standard.

2) We can foresee a possible public backlash if this Standard is adopted as written. We see many utilities needing rate increases to cover the additional costs of implementing and monitoring the more stringent requirements of this proposal. We also believe that the more stringent requirements will have no noticeable impact on reliability. So you'll have the public paying more and seeing no change in reliability and questioning why.</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum vegetation clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. The Standard Drafting team has found that this Standard can not establish any legal basis to require Transmission Owners to exercise rights that do no</td></tr>
</table>

Organization	Question 18 Comment
exist within their transmission line easements or permits.	
Progress Energy Florida	To avoid interpretation errors and provide clarity, the Applicability section for Facilities (4.2) of FAC-003 should include a statement that the standard only applies to vegetation within the Active Transmission Line Right of Way. For example, a fall-in from outside of the Active Transmission Line Right of Way that causes a sustained outage is not a violation of this standard. Any encroachment/outage initiated by vegetation falling from outside of the Active Transmission Line Right of Way should be excluded from violations. The Critical Clearance Zone concept is academically elegant, but when applied in the field, it presents significant implementation, interpretation and enforcement issues: the complexity of determining compliance could have the unintended negative consequences to reliability; removal of vegetation will likely be delayed because of the complexity and accuracy required to determine compliance prior to tree removal; certification that no violations have occurred will require lengthy and costly calculations and survey measurements; the standard refers to Ratings in the determination of line sags and Ratings is not a tightly defined term, PRC-023 requires relays to hold lines in beyond the line Ratings; how will PRC-023 requirements be factored into the Critical Clearance Zone concept. The Critical Clearance Zone concept introduces more complexity and ambiguity into the standard than it resolves. The drafting team needs to develop an alternative to the Critical Clearance Zone concept that is simple, easy to apply and clearly defines at what point a violation occurs. There are over 158,000 line miles of AC Transmission above 200kV in the United States, covering a Right of Way area potentially as large as 3,000 to 4,000 square miles (an area roughly equivalent to Rhode Island and Delaware combined). With billions of stems of managed vegetation, in and along the right of way, even six-sigma performance would result in a number of outages on a system this large. With countless VM processes and assessments that take place daily, it is unrealistic/unreasonable to expect zero-tolerance for random vegetation events (the transmission system is planned/operated to handle at least any single contingency).
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. **The exclusion you request for vegetation falling through the MVCD, regardless of its being form inside or outside the right-of-way, has been added.** **Due to the industry impact that arises from zero tolerance for vegetation-related sustained outages, the Drafting Team tried several approaches but could not find a mechanism in the standard development process to establish a non-zero threshold for outages that was acceptable to FERC staff, because Standard revisions may not lead to less emphasis on reliability.** **The PRC-023 Standard seeks to ensure that transmission protective relays are properly set such that they do not trip a transmission element unnecessarily. This FAC-003 Standard seeks to prevent vegetation related Sustained Outages by requiring Transmission Owners to maintain their Active Transmission Line Rights of Way to be sufficiently clear. These two Standards are not mutually exclusive nor conflict with each other.**	
Kansas City Power & Light	The title and explanation for Table 1 in Attachment 1 is not clear as to it's usage and applicability. It is being confused with the correlation with a minimum clearance and not as a component or building block of the Critical Clearance Zone. Under R10, there may be other methods for consideration of assessing reliability significance of the sub-200 kV lines other than what is

Organization	Question 18 Comment
	listed. Suggest the Drafting Team consider other criteria that an RC should consider in its processes. R10.2 is redundant with R10.1. IROL by definition are those operating limits that represent instability, uncontrolled separation or cascading. Suggest removing R10.2. Under M1.3 the measure requires the annual plan to cover a calendar year. An annual plan may cover a cycle growing season to growing season using the inspection to verify the next seasons work. Suggest removing the language for calendar year.M5, M6, M7 The measures should be requesting the evidence that it has violated the requirements. Good standing programs should not have to defend good practice by providing useless reports. The FAC-003-1 existing requirement R4 for reporting sustained outages is a reasonable and sustainable method that should be retained.R10 should include a periodic review period of annually. Any requirement to maintain current documentation should have a review period.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. **Under M10 (now M11) the language now allows the criteria used in planning studies and analysis to be acceptable measures for R10 (now R11).** **The redundancy in 10.1 and 10.2 you found has been removed.** **The reference to the calendar year that was in M1.3 has been removed.** **M5, M6, M7 language has been changed. These measures now rely on the certification reports to the RE reporting will occur for both full compliance and any violations. The revised standard includes data retention periods as well as more detailed compliance information.**	
Western Area Power Administration, Rocky Mountain Region	1. Further clarification of the definition of the active right-of-way appears to be required. For example, if a tree falls from an area controlled by the utility which is outside of the normal width of the actively managed right-of-way, but this area is not reserved or "intended for other facilities", could this be a violation of a Standards requirement? The narrative discussion within the white paper seems to imply that it is not, but the "intended for other facilities" requirement within Standards definition implies that it would be. 2. As currently presented, FAC-003-2 requires an impractical and unrealistic level of performance from the industry. This level of performance is unwarranted for the overwhelming number and expanse of transmission facilities to which the Standards are applicable. Many of these facilities, such as radial load lines, are not critical Transmission OwnerT or IROL facilities and have a minimal impact on overall grid reliability. The rigorous zero tolerance level of performance is only warranted for those lines that are critical Transmission OwnerT or IROL facilities. 3. The Standards should clearly identify any and all reporting requirements.
Response: The SDT thanks you for your comments. **1. The definition of the Active Transmission Line Right of Way states it is "A strip of land that is occupied by active transmission facilities. This corridor**	

<table>
<tr><th>Organization</th><th>Question 18 Comment</th></tr>
<tr><td colspan="2">does not include the inactive Right of Way or unused part of the Right of Way intended for other facilities.” This definition is not limited only to those parts of the Right of Way intended for other facilities. The SDT has also further clarified the concept in the white paper.

2. Due to the directive given by FERC Order 693 your suggestion for removing some lines above 200 kV from the Standard’s Applicability was not considered. (Excerpt from order 693 paragraph 706 “we did not intend to make this Reliability Standard applicable to fewer facilities than it currently is with the 200 kV bright line applicability, but to extend the applicability to lower-voltage facilities that have an impact on reliability”).

3. Reporting requirements are included in standard in the second posting.</td></tr>
<tr><td>Progress Energy Carolinas</td><td>To avoid interpretation errors and provide clarity, the Applicability section for Facilities (4.2) of FAC-003 should include a statement that the standard only applies to vegetation within the Active Transmission Line Right of Way. For example, a fall-in from outside of the Active Transmission Line Right of Way that causes a sustained outage is not a violation of this standard. Any encroachment/outage initiated by vegetation falling from outside of the Active Transmission Line Right of Way should be excluded from violations. The Critical Clearance Zone concept is academically elegant, but when applied in the field, it presents significant implementation, interpretation and enforcement issues: the complexity of determining compliance could have the unintended negative consequences to reliability; removal of vegetation will likely be delayed because of the complexity and accuracy required to determine compliance prior to tree removal; certification that no violations have occurred will require lengthy and costly calculations and survey measurements; the standard refers to Ratings in the determination of line sags and Ratings is not a tightly defined term, PRC-023 requires relays to hold lines in beyond the line Ratings; how will PRC-023 requirements be factored into the Critical Clearance Zone concept. The Critical Clearance Zone concept introduces more complexity and ambiguity into the standard than it resolves. The drafting team needs to develop an alternative to the Critical Clearance Zone concept that is simple, easy to apply and clearly defines at what point a violation occurs. There are over 158,000 line miles of AC Transmission above 200kV in the United States, covering a Right of Way area potentially as large as 3,000 to 4,000 square miles (an area roughly equivalent to Rhode Island and Delaware combined). With billions of stems of managed vegetation, in and along the right of way, even six-sigma performance would result in a number of outages on a system this large. With countless VM processes and assessments that take place daily, it is unrealistic/unreasonable to expect zero-tolerance for random vegetation events (the transmission system is planned/operated to handle at least any single contingency).</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time.

The exclusion you request for vegetation falling through the MVCD, regardless of its being form inside or outside the right-of-way, has been added.

Due to the industry impact that arises from zero tolerance for vegetation-related sustained outages, the Drafting Team tried several approaches but could not find a mechanism in the standard development process to establish a non-zero threshold for outages that was acceptable to FERC staff, because Standard revisions may not lead to less emphasis on reliability.

The PRC-023 Standard seeks to ensure that transmission protective relays are properly set such that they do not trip a transmission element unnecessarily. This FAC-003 Standard seeks to prevent vegetation related Sustained Outages by requiring Transmission Owners to maintain their</td></tr>
</table>

Organization	Question 18 Comment
Active Transmission Line Rights of Way to be sufficiently clear. These two Standards are not mutually exclusive nor conflict with each other.	
Southern California Edison Company	SCE notes that Section C (Compliance) is incomplete and that the associated levels of Non-Compliance listed in FAC-003-1 may be different from those proposed for FAC-003-2. SCE reserves the right to revise its initial comments and submit additional comments regarding the requirements, measures and compliance portions of FAC-003-2.
Response: The SDT thanks you for your comments. Draft 2 will be a complete Standard for you to review.	
SERC OC Standards Review Group	The SERC OCSRG recommends that the definition of "Active Rights of Way" be revised as follows: "A strip of land, designated by the Transmission Owner, that is occupied by active transmission facilities. This corridor does not include the inactive or unused part of the Right of Way set aside by the Transmission Owner for other facilities or uses." The SERC SOSRG recommends that this standard should exclude radial to load facilities and, for consistency, all 200 kV and above lines should not be included in the standard unless they meet the same requirements as sub 200 kV lines.
Response: The SDT thanks you for your comments. The SDT opted to retain the "bright line" of 200kV without further qualifications such as radial to load transmission facilities, due to the directive given by FERC Order 693 (paragraph 706 "we did not intend to make this Reliability Standard applicable to fewer facilities than it currently is with the 200 kV bright line applicability, but to extend the applicability to lower-voltage facilities that have an impact on reliability".	
Western Utility Arborists	Any standard that is developed should not contain advisory-type language? it should be declarative in tone. For example, in R1.4, the ending clause that begins "and may include actions" should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program. ADDITIONAL COMMENTS We have prepared, and will submit via email, additional comments regarding our online submission. If the ability to submit them electronically is not available on this website, we will send the complete document via email to Harry Tom and would ask that it be reviewed and considered by the drafting team.
Response: The SDT thanks you for your comments. The phrase in R1.4, "and may include actions" has been removed from the revised standard in support of your suggestion. **Please refer to the various responses to your comments provided in the individual questions. The changes to the standard in this reposting and the responses to your comments on questions 1-17 are intended to serve as a reply to your various comments.**	
Florida Power & Light	FPL believes the Vegetation Management standard should concentrate on grow-in tree issues that contribute to cascading or blackout events as stated in the purpose statement. Fall-in trees from either on or off ROW do not in-and-of themselves cause cascading or blackout events. Transmission systems are appropriately designed to handle incidental outages under N-1 conditions which are the case in fall-in type outages. Requirements relating to fall-in and blow-in outages (R6 and R7), which deal with incidents resulting from

Organization	Question 18 Comment
	force majeure or acts of God, should be removed to allow resources to be allocated to addressing events related to grow in interruptions. Because of an utter lack of control or such situations, no Standard or regulation places a duty on one to control force majeure or acts of God, yet that is precisely what R6 and R7 intend to do. If R6 and R7 stay in its current form, this will be yet another reason why this Standard as written will be unenforceable. FPL recommends the following approach. The entire US Transmission system was built under the National Electric Safety Code (C2). That code uses the Reference Component as the initial building block for establishing the lowest height of a conductor for all operating and designed environmental conditions. Over most open land this distance is 14 feet. FPL recommends creating a new requirement to clearly define a trimming standard. New Requirement At time of trimming, trees under conductors should be trimmed or removed so that the average growth would remain below the Reference Component of Rule 232 in the National Electric Safety Code C2. The wire zone should extend to the blowout distance calculated at 39 miles per hour (Fresh Gale) not to exceed the Active Transmission Right-of-Way. Where the Transmission Owner can not achieve that clearance, they shall have a permanent (ex. raised conductor) or interim (ex. short trim cycles) corrective action plan in place to prevent tree wire conflicts. Permanent corrective action plans should reside in the Transmission Owner's vegetation program record keeping system (database) for application when that line is maintained or inspected. Trees to the side of the ROW should be maintained at the edge of the Active Transmission Right-of-Way. The value in this approach is in its application by arborists and tree trimmers in field conditions. This approach is clear and measurable without a surveyor or an engineer present. The line design calculations were made to the NESC Standard at the time the line was built and incorporate all potential conductor locations within its flight path. As it stands now if there is a violation to R4, R5, R6, or R7 it is already too late. The standard should seek to identify and correct poor performers before they create a reliability threat to the system. In the field, a poor performer has many trees close to the line and will have to do many emergency cuts. It will also have more momentary interruptions before it has a single Sustained interruption. Sustained Interruptions have a history of contributing to cascading and blackout events. The standard should measure performance and penalize poor performance. The changes below reflect performance measurements with a graduated penalty applied to the metric. Change R2 to read Each Transmission Owner shall implement its Imminent Threat procedure when the Transmission Owner has knowledge, obtained through normal operating practices or notification from others, that the tree / conductor distance is less than the minimum clearance distance as specified in Table 2 of ANSI Z133.1-2006 (the minimum approach distance for qualified line-clearance arborists or qualified line-clearance trainees). Transmission Owners are to document and report activation of the Imminent Threat Procedure for violation of Table 2. Activation of the Imminent Threat Procedure for other causes shall not be reportable. The Violation Severity level should read: Activation of the Imminent Threat Procedure for encroachment of Table 2 of ANSI Z133.1-2006 (the minimum approach distance for qualified line-clearance arborists or qualified line-clearance trainees) has the following severity level: Lower ? Greater than 5 per 1000 miles of line and less than 7 Moderate ? Greater than 7 per 1000 miles of line and less than 9 High - Greater than 9 per 1000 miles of line and less than 13 Severe - Greater than 13 per 1000 miles of line

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	Trees inside of Table 2 can only safely be trimmed under a clearance from the system operator, using special techniques under a line right of way from the system operator, or by a lineman with a live line permit from the system operator. No utility wants to let a tree get so close to energized lines such that it has to take the line out of service for a tree trim. It should be noted that Table 2 represents an established industry standard which is normally found placarded on the side of every tree trimming easement truck and bucket truck. It is minimum knowledge for every qualified line-clearance tree person under OSHA regulations. This is a distance that field personnel understand. New R5 to read: Each Transmission Owner shall minimize Momentary Outages of applicable lines due to vegetation growing into a conductor with the following exceptions:? Sustained Outages of applicable lines that result from natural disasters.? Sustained Outages of applicable lines that result from human or animal Activity. The Violation Severity level should read: Lower ? Having Momentary Outages Greater than 3 per 1000 miles of line and less than 6 Moderate ? Having Momentary Outages Greater than 6 per 1000 miles of line and less than 8 High - Having Momentary Outages Greater than 8 per 1000 miles of line and less than 12 Severe - Having Momentary Outages Greater than 12 per 1000 miles of line New R6 to read: Each Transmission Owner shall minimize Sustained Outages of applicable lines due to vegetation growing into a conductor with the following exceptions:? Sustained Outages of applicable lines that result from natural disasters.? Sustained Outages of applicable lines that result from human or animal Activity. The Violation Severity level should read: Lower ? Moderate ? High - Having Sustained Outages Greater than 1 per 1000 miles of line Severe - Having Sustained Outages of 2 or greater per 1000 miles of line These VSL's listed above constitute a strawman for discussion. The drafting team could request historical performance data from Transmission Owners to statistically evaluate where the VSL should be set. As time progresses, future performance data could be re-evaluated to reset the limits. These changes bring the standard back in line with measurable and auditable requirements which provide practical field measurements to the personnel who can make the difference. These parameters provide measurements to indicate the tree health of the system. On a separate note, FPL believes that clarifying information captured in footnotes within the standard should specifically be referenced and made part of the standard. These notes add clarity and better define the standard requirements.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive	

Organization	Question 18 Comment
industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. **The Drafting Team reviewed the exclusion in R6 and R7 and reached consensus that the stated exclusions are adequate to exclude force majeure or acts of God.** **This posting includes under R1 the new section 1.6. That would make the proposal you offer related to maintaining the height of trees above ground level to be a method for the TO to select. The language also allows TOs to select a separation distance between the conductor and the vegetation. When lines traverse terrain with significant changes in elevation within spans the latter method may be more practical.** **Changes made to utilize the MVCD as observed in real time will provide the clarity and measurability you requested.** **R2 has been revised to ensure that the process is used only for conditions that require immediate actions to prevent a sustained outage. Other factors which under some conditions would not pose an imminent threat of a sustained outage were purposely omitted to provide clarity and consistency of application.** **Since R2 is binary requirement its VSL cannot be gradated as you suggest.** **R5 has been left as a binary requirement with a zero tolerance in lieu of a gradated metric in the requirement as you suggest. Due to the industry impact that arises from zero tolerance for vegetation-related sustained outages, the Drafting Team tried several approaches but could not find a mechanism in the standard development process to establish a non-zero threshold for outages.** **Momentary outages are purposely not included because of the challenges they pose during investigation. These problems often lead to unreliable, inconsistent, false, or missing reports. Furthermore momentary outages caused by vegetation have not been a historical cause of cascading or widespread outages.**	
Santee Cooper	The SDT should clarify that Transmission lines operated at 200 kV and above is for lines that are network facilities. Radial load transmission facilities operated at 200 kV and above should not be subject to this standard as they would not lead to SOLs or IROLs. M2 requires evidence that a Transmission Owner implemented its imminent threat procedure upon knowledge of a Critical Clearance Zone breach. M4 requires evidence that there were NO encroachments into the Critical Clearance Zone. These two measures are in conflict with one another. If a utility provides evidence for M2 then they are in violation based upon M4.M4 and M5 requires a utility to provide "proof to the negative". These measures should be removed from the standard. R10, R11, M10, and M11 should be removed from this standard as critical facilities are identified through the PRC standards.
Response: The SDT thanks you for your comments. **Regarding your request to line applicability to only network lines above 200 kV FERC in order 693 paragraph 706 stated "we did not intend to make this Reliability Standard applicable to fewer facilities than it currently is with the 200 kV bright line applicability, but to extend the applicability to lower-voltage facilities that have an impact on reliability". The standard drafting team therefore does not see that honoring your request as one that would be**	

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permissible. **Regarding the conflicts you cite between M2 and M4, please note the revisions in this posting for R2, R4 and the associated measures. The conflict you reference should now be resolved since the distance in R4 is not the exclusive basis for implementing R2 and the concept of the "CCZ" has been removed from the revised standard.** **In M4, the language is now changed to remove the "proving a negative" dilemma.** **There is a 200 kV bright line for applicability in this standard; therefore it is appropriate for the applicability for sub 200 kV lines to be determined within this standard in lieu of the PRC standards.** **Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time.**	
Southern Company	We would like to re-emphasize our concern over the zero tolerance philosophy of FAC-003-1 which is continued in this proposed revision. FAC-003 has been singled out as the only zero tolerance NERC standard. Compliance should not be based on the encroachment of vegetation into a theoretical, pre-defined zone, but on the occurrence of a sustained outage, as stated in the document's Purpose Statement. We agree with the philosophy utilized in other NERC standards where a clearly discernible compliance event signals a review of the Transmission Owner's plans, policies, and procedures to determine the effectiveness of the entity's programs and spirt toward compliance. Applicability Section 4.2 describes the Facilities pertinent to this Standard. Recommendation is to restructure the sentence by relocating the parenthetical phrase: Transmission lines operated at 200kV or higher, and transmission lines operated below 200kV designated by the Reliability Coordinator as being subject to this standard ("applicable lines") including but not limited to those that cross lands owned by federal, state, provincial, public, private, or tribal entities. Requirement R3Recommend rephrasing to say: Each Transmission Owner shall conduct vegetation inspections of all applicable lines in accordance with the frequency specified in its transmission vegetation management program. Requirement 10The standard does not mention whether or not the results of this specific assessment methodology are supposed to be compiled and maintained. The resulting information could be labeled as sensitive and possibly critical since the loss would place the grid at an unacceptable risk of instability, separation, or cascading failures. If the resulting information becomes auditable (subject to discovery and posting) then precautions must be taken that are comparable to those designed to preserve the integrity of critical assets or critical cyber assets. We would like to express our sincere appreciation and thanks the drafting team for their efforts.
Response: The SDT thanks you for your comments. **Due to the industry impact that arises from zero tolerance for vegetation-related sustained outages, the Drafting Team tried several approaches but could not find a mechanism in the standard development process to establish a non-zero threshold for outages that was acceptable FERC staff**	

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because revisions to a Standard may not lead to less emphasis on reliability. **The standard has been revised to remove the violation for encroachment into a theoretical zone and is now based on an observed encroachment in real time inside a distance where flashover becomes a possibility.** **The Drafting Team considered the applicability wording with the ("applicable lines") to be acceptable as written.** **R3 has been revised as you recommended.** **The Drafting Team agrees that documentation regarding the methodology used to determine applicability of lines below 200 kV should have similar precautions for confidentiality as other critical assets or critical cyber assets.** **The issue of transmission line applicability is addressed in FERC Order 693.**	
Bonneville Power Administration	There is a typographical error / omission in the Technical Reference on Page 36, which states, "R6. Each Transmission Owner shall prevent Sustained Outages of applicable lines due to the blowing together of vegetation and a conductor with (sic) Active Transmission Line Right of Way) operating within design blow-out conditions) with the following exception: . . . " I believe the intent is for the statement to read "due to the blowing together of vegetation and a conductor WITHIN Active Transmission Line Right of WAY". This change is needed to make the technical reference consistent with R6. as it appears in the Standard, the definition of Active Transmission Line Right of Way on Page 5 of the Technical Reference, as well as the terminology used on Page 37 in describing Fall-into outages. This needs correction.
Response: The SDT thanks you for your comments. The technical reference error is noted and has been corrected by the SDT.	
Public Service Electric and Gas Company	These comments were prepared by Richard Wolowicz, Manager Vegetation Management, on behalf of Public Service Electric and Gas Company ("PSE&G"). PSE&G also joins with and supports the comments filed by the Edison Electric Institute (EEI) in this matter.
Response: The SDT thanks you for your comments. Please see our response to EEI.	
FirstEnergy	FE provides these additional comments for consideration: 1. Regarding the Applicable Facilities - Section 4.2.2 would be more appropriately placed under Sec. 5 "Effective Dates" since it deals with the timeframe the Transmission Owner has to implement its Transmission Vegetation Management Program on sub-200 kV lines.-Section 4.2.3 - We suggest removing this section. First energy does not agree that this standard should dictate the amount of time a Transmission Owner has to obtain compliance with this standard for newly acquired transmission lines. It should be the responsibility of every organization to "self-report" its compliance issues and planned mitigation plans for all standards when they acquire new lines or facilities. If the SDT believes this should be explicitly stated, then it should recommend to NERC that explicit language be placed in the NERC Rules of Procedure. No other standards set timetables for newly acquired facilities and this standard should be no exception. 2. Regarding R1.1, this subrequirement requires the Transmission Owner to specify the methodologies it uses to control vegetation. It

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	should be clear that not all of these methodologies are required to be deployed in every situation (as explained in the white paper pg.12). We suggest rewording the requirement as follows: "R1.1. Specify the methodologies that the Transmission Owner may use to control vegetation." 3. R1.5 requires a process for "interim corrective action" be specified in the Transmission Vegetation Management Program. However, the standard does not explicitly specify that this corrective action be implemented when the Transmission Owner is constrained from performing vegetation maintenance as planned. 4. As written, in addition to the responsible RC, R10 may imply that this requirement is also the responsibility of the Transmission Owner(s) and neighboring RC(s) due to the use of the term "jointly". Also, R10 should require the RC submit the list of designated lines below 200 kV to the Transmission Owner(s) and neighboring RC(s) within a reasonable time-frame after its completion. We suggest rewording and addition of subrequirements to R10 as follows: R10. Each Reliability Coordinator, in consultation with its Transmission Owner(s) and neighboring Reliability Coordinator(s), shall prepare and keep current a list of designated applicable lines that are operated below 200kV, if any, which are subject to this standard. R10.1. The RC shall submit the list to the impacted Transmission Owner(s) within 30 calendar days of completion and/or revision. R10.2. The RC shall submit the list to its neighboring RC(s) within 30 calendar days of completion and/or revision. Lastly, measure M9 will need to add sub-measures for the proposed additions above. 5. Requirement R10 should require that the RC ONLY uses the assumptions detailed in R10.1 and R10.2 to designate a line as significant. Also, R10.1. should reference the IROL methodology standard FAC-011 since it directly ties into this requirement. Also, in R10.2, "grid" should be replaced with "BES" and the term "failures" is not necessary. We suggest re-wording R10, R10.1 and R10.2 as follows: R10. Each Reliability Coordinator shall document its method for assessing the reliability significance of sub-200kV lines and shall be based only on the following: R10.1 Transmission lines whose loss would result in the exceedance of an Interconnection Reliability Operating Limit (IROL) as determined by standard FAC-011. R10.2 Transmission lines whose loss would place the BES at an unacceptable risk of instability, separation, or cascading.

Response: The SDT thanks you for your comments.

The placement of Section 4.2.2 was chosen to allow the TO time to bring those lines into compliance which are identified by future studies well after the effective dates in Section 5.

The SDT chose to leave Section 4.2.3 as it does provide a reasonable time allowance (limitation) to bring the subject lines into compliance. {note for a newly acquired line to have not previously been subject to the standard it may have been 1) owned and operated by a private entity such as a mining company that was not connected to the grid, 2) was a de-energized line not in operation until it was acquired by the TO, 3) was previously operated at

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less than 200kV but was insulated for an operated at 200kv or higher, or 4) some similar situation to 1-3 above} The SDT sees this Section as following the Rules of Procedure Standard Applicability Section as noted on page 9 to "identify any limitations on the applicability of the standard based on electric facility characteristics". **The SDT modified Requirement R1, Part 1.1 as suggested. The standard does not explicitly state that the interim corrective action process in 1.5 must be implemented. The SDT suggests that the other requirements in the standard related to outages and imminent threats and encroachment provide necessary and sufficient incentives for TOs to utilize the process when and if required.** **R9 and R10 (now R10 and R11) have been revised to replace the RC with the PC as the applicable functional entity. The verbiage "in consultation with" has been replaced by "shall consult with its Transmission Owner(s) and neighboring Planning Coordinators to obtain input to develop the list". Since this list is prepared by the PC for the TO to know of any sub 200 kV line(s) that the TO must maintain, the SDT does not see a benefit to adding a requirement that the PC will provide the list to the TO.** **The SDT chose to keep the word "grid" in lieu of BES to avoid confusion related to the fact that the BES generally includes all lines above 100 kV as defined by the Regional Reliability Organization and this standard does not.** **Other changes were made in the language of R9 and R10 to which incorporate parts of recommendations from other commenters and FE. Requirement R10, Parts 10.1 and 10.2 were redundant, and Part 10.1 was deleted and Part 10.2 was translated into a separate requirement, R11.**	
Midwest ISO Stakeholders Standards Collaborators	FAC-003-1 lacks clarity that is essential for understanding what is necessary for compliance. The proposed FAC-003-2 needs to be simplified to aid with field implementation and compliance interpretation. Currently, it does not provide the clarity and simplification needed by Transmission Owners and regulatory bodies to enhance reliability.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. These changes should add the clarity and simplification that your and other commenters suggested was needed for field implementation.	
SERC Compliance Staff	SERC staff continues to find the Applicability section of the standard to be confusing and contentious. While we recognize it is the intent this section to make the standard applicable t all entities that own transmission lines that operate at greater than 200 kV, this section should not be written to be applicable to transmission lines. Only registered entities can be held accountable for compliance with the standards. SERC staff believes the applicability should be rewritten to include Transmission Owners, Distribution Providers, and Generation Owners that own transmission lines with the characteristics defined in Section 4.2. This would eliminate the need to make register, for example, a Distribution Provider that own a 230 kV line that serves load as a Transmission Owner and make them subject to the requirements of FAC-001 and FAC-002. SERC Staff also suggest the applicability could be handled as it is in PRC-005-1 where the applicability is qualified as 'distribution provider that owns..' and 'generator owner that owns..' or in a similar manner that captures the appropriate subgroup but does not include unintended entities. SERC Staff believes a flashover between vegetation and overhead ungrounded supply conductors that occurs, whether or not the

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	flashover results in a Sustained Outage, is clear evidence of an unallowable encroachment of vegetation into the space that should be avoided and thus should be identified as evidence of a violation of the standard. SERC staff has also found that excluding outages resulting from "earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner?" results in inconsistencies in reporting because of the inconsistency of the Transmission Owners' definitions of same. If such exceptions are to be allowed, a consistent method of determining the acceptability of those exemptions should be pursued.

Response: The SDT thanks you for your comments.

The intent of the Facilities section under Applicability which you suggest is confusing and contentious, was chosen to follow the Reliability Standards direction under Applicably, specifically "if not applicable to the entire North American bulk power system, then a clear identification of the portions to which the standard applies…"

The issue you raise with respect to Distribution Owners and Generation Owners does not appear to be supported when one reviews the definition of a Transmission Owner in the NERC Glossary "The entity that owns and maintains transmission facilities." The SDT is concerned that your suggestion will add confusion to the standard." PRC-005-1 properly addresses the coordination needed between transmission protection and the interface with distribution protection at the point of transformation. There is no comparable expectation for vegetation maintenance on the low voltage side of a transmission to distribution transformer to be subject to this standard. Simply put, either someone owns transmission or does not. It is of no matter whether they may also be a DP or GO. Until the functional model includes provisions to state that "all transmission is not equal", the applicability should remain.

Your concern about flashovers that do not result in Sustained Outages needing to be stated as violations of this standard has been discussed at length by this SDT. The interest is to have a Standard that is not subject the levels of uncertainty associated with any automatic operation which is returned to service by either manual or automatic means. These events are very often not possible to identify, many times misidentified often occur during conditions that have several possible explanations (such as high winds blowing conductors together, wind-blown debris, lightning, contamination flashovers during the onset of wind and rain storms) and do not have a historical basis for ever creating a cascading event. Inclusion of these events as violations in the standard could also cause significant additional costs for extensive investigations by TOs to prove their "innocence" for events that any properly designed and operated transmission system should withstand with no more challenge that the far greater number of lightning, and equipment failure events (cross-arms, insulators, conductor splices, poles) nor ever been the subject of momentary opera being.

Members of the SDT attempted to get the TADS reporting requirements to clearly identify those faults on transmission lines that required maintenance to return the line to service. If such a definition was entertained, then a great deal of the uncertainty is cleared. However there are still conditions where trees and poles are found down after apparent high wind conditions in locations remote to the nearest weather reporting station that depend on assumptions as to which fell first the pole or the trees. The zero tolerance nature of this standard and the Penalty Matrix values should not be tied to anything with a high degree of assumption and uncertainty. Therefore the standard has been revised and worded to have the violation of MVCD as observed in real time.

As an added note there is unnecessary confusion caused by simply labeling the automatic operation line operations as momentary, sustained, and/or locked-out. If a line is not reclosed within moments of the automatic interruption, but is later "test closed" was the line truly unavailable? Was the

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reclosing signal/command properly performed initially? Did the TOP ever truly lose control of this line if all that was required was another close attempt? The true nature of the loss of a line is manifested when it is known that a clearance must be issued such that the line is removed from the TOP's control. **The SDT has reviewed the data on vegetation related reported outages on the NERC website. There are 223 reports of outages in that data covering the period January 2004 to March 2009. The associated documentation with these events indicate that TOs are supplying supportive information to indicate that the level of any disaster exclusion is sufficient to identify that design criteria was exceeded. Further specifics on the threshold for each disaster would not ensure that weather data would be adequate to support each location/situation.**	
ITC HOLDINGS	V1 was a better written standard and had clear requirements on reporting and who was to report violations etc. When and how are violation to be reported is not mentioned in the V2. The standard should clearly identify all reporting requirements. Standard development should focus on practicality for the field personnel in terms of implementing the standard and enforceability. Version 2 is not as user friendly for field personnel and ambiguous at best which requires an impractical and unrealistic level of performance from the industry. This standard needs to stress that it applies to vegetation within the Active Transmission Right of Way. Vegetation from outside the active ROW, falling through the Critical Clearance Zone should not be a violation. V2 needs further clarification of the definition of the active ROW.
Response: The SDT thanks you for your comments. The issue of reporting has been addressed in the compliance section of the revised standard. **The changes made to R4 focus on the practicality for field implementation that you suggest. The exclusion you request for vegetation falling through the MVCD, regardless of its being form inside or outside the right-of-way, has been added.** **The definition of the active right of way was debated at length and determined to be best stated in its current form.**	
Exelon	Applicability. 4.2.2 is unclear. If 4.2.2 is intended to cover Generator Owner interconnections, say so uniquivocally. Do not rely on future changes to the NERC Registry Criteria or other "global" solutions if the intent is to make the standard applicable to Generation Owners who own generator leads. Exelon would like to reemphasize our concern with implementing the requirements if the Gallet equation derived Critical Clearance Zone is used. ANSI A300 part 1 and part 7 should be part of the standard as they provide independently recognized valid methods and guidance to conduct maintenance on the ROW corridor.
Response: The SDT thanks you for your comments. **The issue you raise with respect to Generation Owners does not appear to be supported when one reviews the definition of a Transmission Owner in the NERC Glossary "The entity that owns and maintains transmission facilities." The SDT is concerned that this suggestion to add the Generation Owner will add confusion to the standard." The SDT does not agree there is ambiguity. Either an entity is a TO or not.** **The Gallet Equations distances were chosen in lieu of ANSI A300 for clearances because the Gallet is a distance that is necessary to prevent flashover.**	

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The ANSI values are related to worker and public safety not flashover between the conductor and the vegetation.	
Central Maine Power Company	The White paper is an important support document and should remain as an attached reference to FAC 003. The white paper should clarify that capable tree species should always be removed from the border zone, except in selected areas where topography includes deep ravines.
Response: The SDT thanks you for your comments. The standard was designed to allow the Transmission Owner the flexibility to design its TVMP. Further, ANSI A300 is also footnoted in the standard as a "best practice". The White Paper will remain a reference for this Standard and text has been added to try to provide additional guidance as you suggest.	
American Electric Power (AEP)	The definition for Critical Clearance Zone (Critical Clearance Zone) on page 2 of the proposed draft Standard does not specify the Rating (summer, winter, normal, emergency, etc.). This suggests that different Critical Clearance Zone s apply at different times of the year and thus that vegetation in the area might be outside the Critical Clearance Zone at certain times of the year and inside the Critical Clearance Zone at other times. AEP suggests that this may not have been the intent of the drafting team. Also, the term "design blowout" is not defined; thus, it appears that it will be up to the Transmission Owner and the auditor to determine the bounds of the Critical Clearance Zone . AEP again suggests that this may not have been the intent of the drafting team. Requirement R9 contains the clause "within the extent of its easement and/or legal rights". This intent of this clause is unclear and its rationale is not obvious. AEP suggests that this clause be removed or at least reworded for clarity.
Response: The SDT thanks you for your comments. The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. The verbiage you suggested removing form R8 (now R9) was removed. Finally, the new Requirement R1 should address the concern about sag and blowout in that it talks about planning to keep vegetation out of all positions the conductor may be for all design conditions.	
Platte River Power Authority	The white paper ensures consistent interpretation of the standard. Perhaps the lack of such a paper in the first version of the standard contributed to the varying interpretations.
Response: The SDT thanks you for your comments. The White Paper will accompany this Version as a Reference document.	
City of Tallahassee	Attachment I. Titles are different between page 8 and 9. Page 8 should have (D) after Distances. Page 9 should have indication that it is "continued" since the table spans multiple pages.
Response: The SDT thanks you for your comments. The SDT has reformatted the table in Attachment 1 of the Standard.	
Northern California	Section A. 5. Effective Dates: This is extremely vague and I would not know the actual effective date. Whose regulatory approval is

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Power Agency (NCPA)	needed? If this is meant to leave flexibility between FERC and the Canadian entities, please write it that way. Most effective dates are clear and concise, i.e., "the first month following approval by FERC". Let's clear this up and avoid a subsequent interpretation request.
Response: The SDT thanks you for your comments. The wording of this portion of the standard (the Standard's effective date) is governed by NERC policy. The process for approval is different in different jurisdictions – some Canadian Provinces approve a standard when it is approved by the NERC Board of Trustees, other Provinces have other mechanisms for approving standards. For entities that operate in the United States, the FERC is the regulator that must approve the standard. As written, the standard will become effective in the United States the first calendar day of the first calendar quarter one year after FERC approval.	
Northern Indiana Public Service Company	While I very much respect the industry commitment and expertise of the drafting team members, the resulting revised standard reflects an effort to "revolutionize" the standard, when an "evolution" of the current standard would better serve the interests of system reliability. The kinds of wholesale changes proposed in this revision evoke real concerns about governmental regulations being a moving target and in many aspects, backs away from requirements that have led to real progress in UVM made since the 2003 blackout. For example, our company has invested tens of thousands of dollars and countless man-hours to comply with provisions of the existing standard only to see them simply done away with under the proposed revised standard. These investments were made based on an industry consensus standard as well as a realization that the requirements were reasonable and essential to improving system reliability. Where is the evidence that the current standard is not working as intended? What has changed in the last few years to warrant a complete re-write of the current standard? Most UVM professionals will agree there are some changes that need to be made to address FERC's concerns and to clarify intent. However, as presently written, I will recommend our T.O. vote against adoption of FAC-003-2.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The Critical Clearance Zone concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. Moreover, certain language changes were needed to comply with directives in FERC Order 693. The changes proposed are meant to capitalize on programs already implemented, not to discard them.	
Tampa Electric Company	Good start. However, this will need additional work and review predicated on the above comments.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time.	
Orange and Rockland Utilities Inc.	Clearance 1 has been eliminated from this draft. Version 2 as drafted only requires that Transmission Owners address vegetation that approaches the Critical Clearance Zone . This is essentially equivalent to Clearance 2 in version 1, a minimum clearance. Although unlikely this could result in some Transmission Owners adopting a just in time vegetation management concept that focuses on

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	maintaining minimum clearances, rather than removing incompatible vegetation or achieving greater clearances. Although R1 requires Transmission Owners to design their Transmission Vegetation Management Programs to control vegetation there is no clear requirement to address incompatible vegetation early and aggressively. The drafting team should revisit this and consider returning to some form of Clearance 1 or requiring the Transmission Vegetation Management Program to address removal of incompatible vegetation within their easement rights.
Response: The SDT thanks you for your comments. **The SDT did revisit and reconsider reinserting a Clearance 1. The issue of how and when to remove or control "incompatible vegetation" was also revisited. The SDT decided to leave C1 and the methods to control (or remove) "incompatible vegetation" to the discretion of the TO. Such discretionary measures do not meet the qualifications to be a requirement within a standard.** **Please take a comprehensive look at all the requirements in the standard we are now re-submitting with this posting. Compliance with these requirements will ensure that the TO maintained vegetation such that 1) no controllable sustained interruptions have occurred, 2) no imminent threats were left unaddressed, 3) all the separation distances between the conductors and vegetation every time they were observed were greater than the distance necessary to prevent a flashover.** **Compliance with each of the above requirements can be achieved with inspection and pruning cycles on a frequent basis such as annually, or on a longer term basis such as every 4 years where warranted by local conditions. There are numerous examples in the industry of these different approaches being both appropriate and effective. Just because a "shorter cycle" is utilized, does not mean that a compromised or "just-in-time" concept is has placed the adequate level of reliability of the grid at risk.**	
American Transmission Company	FAC-003-1 lacks clarity that is essential for understanding what is necessary for compliance. The proposed FAC-003-2 needs to be simplified to aid with field implementation and compliance interpretation. Currently, it does not provide the clarity and simplification needed by Transmission Owners and regulatory bodies to enhance reliability. Requirement 1.3: The proposed requirement does not allow enough flexibility for making changes to the Annual Plan. We believe that changes to the Annual Plan should be allowed even if that means delaying something until the next Annual Plan. Our Proposed Changes: Have an annual plan that identifies the applicable lines to be maintained and associated work to be performed. Adjustments to the annual plan are permissible. We believe that our proposed language accomplishes the SDT's intent while allowing for appropriate flexibility.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. Those changes, including the removal of the concept of the CCZ, address and provide the clarity and simplifications you suggest are needed for field implementation of the standard. R1.3 has been revised for to provide clarity. **These R1.3 changes do not explicitly remove the "within the year" clause as you requested, however we do not see the inclusion of that language as restricting appropriate flexibility. It is expected that the annual work plan will be flexible to adjust to changing condition and findings which occur after the plan is first issued for the year, then adjusted within the year as appropriate. Adjustment made within a year may mean accelerating work to the current year that was not in the current year's plans as well as extending work that was initially planned for this year into the future. And when**	

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disasters occur, the SDT has addressed an appropriate extension.	
Xcel Energy	Attachment 1, Table I- Change the title of the table from "Proposed Minimum Vegetation Clearance Distances" to "Critical Clearance Zone Distances". The reason being is that the general public could interpret this table to mean that this is all the clearance that is required by a utility at the time of pruning. Section C, Violation Severity Levels- There is some inconsistency between the C.2 chart and the contents of the Standard and the White Paper. For example, the White Paper specifies that an exception to an R6 blowing together violation would exist for sustained winds of gusts of 45 miles per hour or greater. As to R7, the Standard itself notes that a violation only occurs if the vegetation falling into the line is from within the ROW ? C 2 does not incorporate that requirement. There are two approaches: either note the exemptions within the C 2 chart, or add a footnote to the chart along these lines: "This chart summarizes various provisions, the details of which are more fully set forth in the Standard and White Paper?. We would recommend the later approach. General suggestions: 1) It appears that the FAC-003 Standard is the only "zero tolerance" standard, in some respects. Is this reasonable? 2) There appears to be "advisory" language in this version of the Standard. This type of language should be part of the White Paper, not the Standard itself. 3) Utilities need more support from FERC to deal with regional roadblocks within the USFS regarding the implementation of IVM. The Memorandum of Understanding is not universally accepted within all regions of the USFS.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment parts of those changes address or remove the issues you raise for exemption and footnotes for Table 1. **Table 1 in not intended to be used by TOs to determine how much to prune. This table provides the actual physical separation distances, which if observed, will ensure that flashover from the line to vegetation will not occur. When conditions exist such that the separation is reduced the risk of flashover will become significant. The risk increases as the separation is reduced. Therefore this value represent a threshold which if not violated will prevent flashover, as such it is a valid physical basis for R4 compliance.** **This standard allows the TO to use any combination of pruning, removals of vegetation at ground level, frequency(cycles) of planned maintenance, enhanced inspections, off-cycle corrective maintenance, etc to prevent violations occurring due to vegetation causing a non-exempted sustained outage or MVCD violation.** **Due to the industry impact that arises from zero tolerance for vegetation-related sustained outages, the Drafting Team tried several approaches but could not find a mechanism in the standard development process to establish a non-zero threshold for outages that was acceptable to FERC staff because revisions to Standards may not produce less emphasis on reliability.**	

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<tr><th>Organization</th><th>Question 18 Comment</th></tr>
<tr><td colspan="2">The advisory language in R1.4 has been removed.

The SDT discussed with NERC and FERC the need for support with the USFS issues. The SDT concluded that FERC has no power to change the rights or restrictions within any permit or easement document across privately owned or publicly owned.

Therefore any efforts to improve permits or reduce limitation on permits or easements on federal lands must be handled through other available methods.</td></tr>
<tr><td>Ameren</td><td>While FAC-003-1 lacks clarity that is essential for understanding what is necessary for compliance, the proposed FAC-003-2 needs to be simplified to aid with field implementation and compliance interpretation. Currently, it does not provide the clarity and simplicity needed by Transmission Owners to implement and regulatory bodies to monitor in a manner that will enhance reliability.</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. Those changes address and provide the clarity and simplification you suggest are needed for field implementation of the standard.</td></tr>
<tr><td>Long Island power Authority</td><td>1) Disagree with R1.1. The proposed standard is too lenient on the program documentation required for an effective program. R1.1 should include the words " the program will document the program objectives, method of site evaluation, the definition of action thresholds, the control methodologies, and how the monitoring program is established". There is a wide gulf between listing IVM methodologies and a vegetation program implementing A300.

2) CHANGE: Within Applicable Facilities listed in section 4.2 the phrase Transmission Line should be changed to Overhead Transmission Line. The NERC Glossary definition of transmission Line is: " A system of structures, wires, insulators and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances." The accompanying white paper states the standard is addressing the impact of vegetation growth on overhead transmission lines. The intent of this standard is the development and implementation of a vegetation management program for overhead transmission lines only. By specifically stating "overhead transmission lines in Section 4.2 there will be no possibility of an occurrence of an auditor requesting a vegetation management program for underground lines.</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments. In R1.1 the SDT chose to direct the TO to specify the methods used to control vegetation vs specifying a menu of items that may not be applicable to several TOs due to the limited types of vegetation in their areas. The SDT considered the issue of overhead versus underground and concluded that no further clarification was needed. Further, ANSI A300 is referenced in the Standard as a best management practice. The SDT leaves up to the TO the extent to which it wishes to apply A300.</td></tr>
<tr><td>USDA Forest Service, Southwestern Region, Regional Office for AZ and NM</td><td>I'm having trouble getting comments to "stick" in this section of the form. I have a general concern with the opening paragraph of R1. The wording seems to encourage a Transmission Owner to develop a Transmission Vegetation Management Program in a vacuum. The US Forest Service definitely wants input into the development of an annual work plan and USFS land use authorizations include a requirement for USFS approval of vegetation management plans. It seems much more reasonable to require the Transmission</td></tr>
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	Vegetation Management Program to reflect USFS or any other landowner resource management considerations. This tactic would require more "up front" work, but the end result is a plan which would reflect reasonable landowner input and where the disagreements could be settled ahead of time rather than being left for the night shift. I also believe that some kind of dispute resolution process is needed outside the control of either the Transmission Owner or the USFS. I think that NERC could fill that role very well.
Response: The SDT thanks you for your comments. Underlying landowner rights are outside the purview of this Standard. However, the SDT recognizes the value in "up front" input between landowners and transmission Owners. Notice that in this posting of the standard within Requirement 1 at 1.3.4 the transmission vegetation management program shall "take into consideration permitting and scheduling requirements from landowners and regulatory authorities". Such consideration should aid in addressing the issues you raise.	
Consumers Energy Company	The annual work plan should be designed to avoid vegetation growing into a violation of the Critical Clearance Zone or whatever minimum distance is acceptable. Since the plan can change throughout the year, it needs to be flexible, it should be stated that the plan at a minimum must provide adequate funding to prevent vegetation growth from violating the minimum clearance distance. The flexibility of change should be limited to changing to address emergent needs for vegetation management and not reductions in funding that delay maintenance in the hopes that additional funding at some future point in time will be adequate to remove the backlog of vegetation maintenance. The Purpose of the standard should be revised to state "(To maintain minimum clearance sufficient to avoid any vegetation-related Sustained Outages for all applicable conditions) for all Transmission Lines covered by this Standard" as provided by FERC in Order 693, Paragraph 731. The purpose as stated in FAC-003-2 waters down the intent of FERC to "improve the reliability" and is only applicable to "outages that could lead to cascading".
Response: The SDT thanks you for your comments. The purpose statement language was chosen to explicitly state the outcome to be achieved by this standard. The requirements themselves address, among other things, the Sustained Outages and minimum clearances along with the required supporting language. This separation between the purpose and the requirements appears more appropriate to the SDT. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. Further, funding is not an issue addressed by this Standard.	
National Grid	National Grid has the following comments: 1. Transmission Owners should be able to define their own inspection "year" and not be locked into a calendar year time frame. National Grid performs inspections at least once per vegetation growth year. Under our Vegetation Management Program, growth years are not skipped, and our inspections occur prior to new growth every year. For example, a transmission right-of-way may be inspected in December 2008 and the right-of-way is next inspected in February 2010. Under this scenario, the inspections occurred 14 months apart, but only one growth year occurred between inspections, and each inspection is ahead of the next year's growth. Transmission Owners need this flexibility to deal with regional growth rate differences and climate. 2. Section C., Compliance, of Draft Standard FAC-003-2 states "To be added". Issuance of Draft Standard FAC-003-2 should have been delayed for comments until all sections were complete. This section is likely to include the outage reporting and self-certification

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<tr><th>Organization</th><th>Question 18 Comment</th></tr>
<tr><td></td><td>requirements. Transmission Owners need the opportunity to comment on these items.

3. With the elimination of Clearance 1 and reducing Clearance 2 clearances, there is concern that FERC will view Standard FAC-003-2 as a watered down version of Standard FAC-003-1.</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments.

1. It is recognized that most work management systems typically allow for planned work to be performed within a “band of dates” around a specific end date, such as one-third or one-fourth of an interval. These partial intervals allow for the normal variations that occur in work scheduling. When work is completed within that band of dates it is considered completed “as scheduled”. Compliance to R2 should be examined for the example conditions you offer since you are addressing the implementation of the inspections. If the frequency was stated in the vegetation management program as once per calendar year, and if the work was completed “as scheduled” then the TO would be compliant.

2. The compliance elements are included with the second posting of the standard and will be subject to stakeholder comments.

3. Effort were undertaken to address in the standard various elements for outages, imminent threats and clearances in a manner that was responsive to a substantial number of industry concerns. The SDT is striving to meet industry stakeholder concerns with a standard that will be approved by its ballot pool, the NERC BOT, and regulatory authorities, including FERC</td></tr>
<tr><td>Pacific Gas & Electric Co.</td><td>1) The standard should be clear that it applies to all Federal and Non-Federal land. PG&E further recommends additional language specifically dealing with Federal land such as application of ANSI A300.

2) The standard should specify applicability inside substations.</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments. This Standard states in the applicability section that all lands are subject to the standard. Further, ANSI A300 is footnoted in the Standard. Substation facilities are not included in this Standard. This will be addressed in the White Paper.</td></tr>
<tr><td>NV Energy (fka Sierra Pacific / Nevada Power Co.)</td><td>These comments were made with collaboration with other Western Utilities in a conference on this topic held in Denver. Any standard that is developed should not contain advisory-type language? it should be declarative in tone. For example, in R1.4, the ending clause that begins “and may include actions” should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program. NV Energy and the other Western Utilities support the development of this white paper as a way to help ensure consistent interpretation of the standard. Perhaps the lack of such a paper in the first version of the standard contributed to the varying interpretations by the auditors. The utilities understand however that this document is not a legal document and is not binding.</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments. Please refer to the various responses to your comments provided in the individual questions. (R1.4 was modified to eliminate the list of possible actions and the use of the word, “may.”)

The changes to the standard in this reposting and the responses to your comments on questions 1-17 are intended to serve as a reply to your various</td></tr>
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comments.	
San Diego Gas & Electric	We feel that any advisory-type language should be removed from the standard and replaced with wording that is in a declarative tone. We support the development of the white paper as a way to help ensure consistent interpretation of the standard.
Response: The SDT thanks you for your comments. The advisory-type language has been removed form R 1.4	
Hydro One Networks Inc.	Please see our comments on question 3.
Response: The SDT thanks you for your comments. Please see the response to comments on question 3.	
Edison Electric Institute	Overall Comments EEI strongly believes that companies are responding assertively to the requirements in FAC-003-1 and that the existing standard is effective in supporting an adequate level of reliability. The central issue with FAC-003-1 and the draft version 2 centers on circumstances where vegetation encroachments into clearance zones take place and do not result in interruptions. EEI understands that a potentially broad range of interpretations are being applied to the existing standard, resulting in potential violations due to clearance encroachments of any possible design position of the conductor being violations, as well as Sustained Outages. Version 2 should clarify this issue in the context of focusing the industry in the direction that is most effective in establishing an adequate level of reliability. The technical comments provided by EEI seek to address this critical issue. Quantitative analysis on vegetation-related line outages or violations made publicly available do not support the need for a substantive revision of the standard. Analysis needs to recognize a broader range of facts in a consistent manner. Analysis needs to consider whether violations resulted in a Sustained Outage, whether all outages and vegetation encroachment were voluntarily reported prior to enactment of Section 215, or the facts and circumstances surrounding violations. For example, while some entities may perceive a decline in industry performance, it may be that companies are reporting much more completely than in the past. Much more rigorous analysis is needed before concluding that the existing standard must be made tougher. Rather than focusing on whether the standard should be more stringent, EEI believes that the emphasis in the standard development process should focus on practicality, both for field personnel in terms of implementing the standard, and enforceability. Revisions to the existing standard should therefore seek to a) respond to issues raised by FERC in Order No. 693 b) where possible, clarify ambiguities in the requirements, and c) improve industry understanding, practicality, and enforceability. For example, it is impractical to seek development of a ?bright line? set of performance requirements. The standard needs to recognize both the diversity of the continent in terms of geography, topography, and climate, and the critical need to provide field personnel with workable performance requirements. Bottom line; it is very important to recognize that the ultimate goal of the standard is to ensure that vegetation management is conducted in order to maintain an adequate level of reliability, and the industry is achieving this goal. The standard should aim for increasing clarity in the requirements without sacrificing flexibility, since companies expect high monetary penalties associated with Sustained Outages caused by vegetation. In addition, a continued ?zero tolerance? approach to vegetation management will emphasize operational excellence. Seeking ?zero tolerance? on momentary outages is equivalent to pursuit of

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	operational perfection, which is achievable only at extraordinary expense to customers. Therefore, the Standard will be most effective if its elements encourage proactive behavior and provide incentives for Transmission Owners to identify and address vegetation clearance issues before they result in momentary interruptions or Sustained Outages. Vegetation Outage Data In Order No. 693, Paragraph 732, FERC ordered NERC to collect and analyze transmission outage data to inform development of the revised standard. EEI encourages the drafting team and NERC Standards Committee to request that NERC collect and analyze this critically important information. Such analysis provides an important foundation for determining whether the standard can ensure an adequate level of reliability as required by Section 215.Applicability Order No. 693, Paragraph 708, directs NERC to 'develop an acceptable definition that covers facilities that impact reliability but balances extending the applicability of this standard against unreasonably increasing the burden on transmission owners.' In the order, FERC appears to accept the 200-kv threshold, however, continues to ask about these other critical facilities. EEI recommends that the drafting team develop a definition of 'sub- 200kv critical facilities' for use in the standard. Reliance on Reliability Coordinators for developing their own definition raises the likelihood of inconsistent approaches and applications of the term. In addition, the drafting team should consider whether such critical facilities might require expanding applicability to entities other than Transmission Owners. Annual Plan as a Defined Term In order to aid in compliance enforcement and industry compliance, the term 'annual plan' should be a defined term.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. We agree with many of your points. The SDT developed R2 to promote proactive behavior by requiring the recording and documentation of imminent threat procedure implementations. The NERC Transmission Availability Data System is set up to collect the outage data as directed by the FERC. In the revised standard, to address the sub 200 kV facilities to be subject to the standard, the SDT chose the Planning Coordinator (rather than the Reliability Coordinator) for that task. The Planning Coordinator has the wide area view and appropriate time horizon perspective to identify sub 200 kV facilities. The SDT considered the situation where non-TO facilities such as generator "leads" would be subject to this Standard. There is an ongoing discussion within NERC with regard to registration of Generator Owner's as limited TO's. Annual plans have relevance within this Standard's context and are not needed elsewhere. Therefore a glossary definition is not necessary.	
Consolidated Edison Company of New York (CECONY)	CECONY does not feel that, as currently written, the Standard would effectively enhance reliability throughout the industry. We recommend that stricter language be used in the Standard specifically requiring the industry to remove incompatible species on Active ROWs. This should reduce the number of outages resulting from vegetation grow-ins and vegetation fall-ins from inside the Active ROW and help maintain a higher level of reliability. This is currently done at the state level (in NY) and the revised wording in the Federal Standard may help promote consistency industry-wide and avoid confusion. Also, the concept of the Critical Clearance Zone is theoretically strong but it needs to be made simpler for the auditors and field inspectors.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. We agree with many of your points. The SDT developed R2 to promote proactive behavior by requiring the recording and documentation of imminent threat procedure implementations. The NERC Transmission Availability Data System is set up to collect the outage data as directed by the FERC. . In the revised standard, To address the sub 200 kV facilities to be subject to the standard the SDT chose the Planning	

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WECC	Reporting requirements are not identified in the standard. WECC believes that sustained outages caused by vegetation should be reported to the Regional Entity using the existing reporting requirements in FAC-003-1 (Transmission Owners report outages to the Regional Entity). Reports of sustained outages to the Reliability Coordinator should be made for reliability purposes and not compliance purposes. The Reliability Coordinator should not be required to report vegetation outages of individual Transmission Owners to the compliance department.
Response: The SDT thanks you for your comments. The revised Standard reflects changes in reporting requirements.	
Arizona Public Service Company	APS has a comment to NERC on picking the standard drafting team. FAC-003 is a vegetation management standard not an engineering standard. The team members should have been chosen based on managing the vegetation program not because they were engineers. Any standard that is developed should not contain advisory-type language? it should be declarative in tone. For example, in R1.4, the ending clause that begins "and may include actions" should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program. APS supports the development of this white paper as a way to help ensure consistent interpretation of the standard. Perhaps the lack of such a paper in the first version of the standard contributed to the varying interpretations by the auditors. The utilities understand however that this document is not a legal document and is not binding.
Response: The SDT thanks you for your comments. The members of the SDT were selected based on their expertise – the following was taken from the SDT Nomination form: **Candidates should have expertise in one or more of the following areas:** - **Transmission line rights-of-way (ROW) vegetation management or ROW maintenance** - **Transmission line design and ratings** - **Regulatory or legal considerations in ROW maintenance** - **Existing codes and good practices in vegetation management** **Most of the SDT members have expertise in vegetation management.** **The SDT has removed the advisory language in R1.4. The SDT has professional foresters, vegetation managers, system operators and regulators.**	
Baltimore Gas & Electric	The Applicability Section of the Reliability Standards (4.2 Facilities) defines the Transmission Lines (Applicable Lines) that must comply to the reliability standard. This section should clearly state that the scope is limited to the facilities that are Bulk Electric System facilities

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Company	consistent with the Bulk Electric System definition as defined by the Regional Entity. Regarding M5, M6, M7:The intention of these paragraphs is unclear to me as written. At first glance, it appeared that the paragraphs were asking for a negative to be proven, e.g. prove that you didn't have any tree-related outages. Anther possible meaning is that utilities have to justify the cause of any outage that may occur. As such, the burden of proof is on the Transmission Owner to provide evidence that an outage was not caused by trees. If an outage were to occur but the Transmission Owner could not find any evidence of the cause, the wording in these paragraphs suggests that by default, the outages will be classified as tree-related. If these paragraphs are intended to assign an outage cause to an outage that has already occurred, then perhaps they could be reworded to say something to the effect of: "Transmission Owner shall provide results of investigation into all transmission outages?? "If these paragraphs are not intended to assign an outage cause to an outage that already occurred, but to provide a mechanism to report outage performance that is currently covered in M3 and M4 in FAC-003-1, then perhaps they could be reworded to say something to the effect of: "Transmission Owner shall provide documentation of tree-related outage performance on a quarterly basis. Investigation results for unknown outages shall also be provided on a quarterly basis." Or as one last suggestion, the wording could simply be: " The Transmission Owner has evidence that there was a Sustained Tree-related Outage?. Regarding the Tech. Reference, I thought that overall it was helpful and will be valuable to help provide guidance for Transmission Vegetation Management Program development and implementation. The area that covers the Active/Inactive R/W should be more clearly explained and illustrated, particularly with respect to the towers with space for another circuit on one side of the structures.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The old M5, M6, and M7 have changed in a manner that should clarify their interpretation as you requested. The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are now required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. **Reporting requirements are included in the compliance section with this posting.** **The SDT will attempt to incorporate your suggestions on illustrations for double circuits in the white paper with the final posting of this standard.**	
Duke Energy Corporation	FAC-003-1 lacks clarity that is essential for understanding what is necessary for compliance. The proposed FAC-003-2 needs to be simplified to aid with field implementation and compliance interpretation. Currently, it does not provide the clarity and simplification needed by Transmission Owners and regulatory bodies to enhance reliability.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. These changes are directed at the clarity and simplification you requested for effective field implementation and compliance interpretation.	
CenterPoint Energy	The proposed FAC-003-2 has gone FAR beyond what was contemplated by the Commission in FERC Order 693 and equates to a total re-writing of the Standard for no apparent reason. The Commission's determination dealt with the following areas: (1) applicability; (2)

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	inspection cycles; and (3) minimum clearances on National Forest Service lands. For instance in Paragraph 729, the Commission states, “As proposed in the NOPR, the Commission approves Reliability Standard FAC-003-1 with no proposed modification on the issue of clearances. The Commission reaffirms its interpretation that FAC-003-1 requires sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions?.” Rewriting the minimum clearances introduced a new set of confusing definitions, and further burdens the Transmission Owners with new documentation requirements with little if any benefit when compared to the Clearance 2 concept in the existing Standard. A preferred approach would have been to incorporate the following few items into the existing Standard: (1) the RC versus the RRO; (2) the designation of a specific inspection frequency; (3) the Gallet equation; and (4) the applicability to National Forest Service lands. We agree that the removal of requirements for quarterly reporting of outages, Clearance 1, and personnel qualifications reduces the burden on the Transmission Owners and does not affect the purpose of the standard to prevent vegetation outages. The Standard could meet its purpose and be streamlined by considering the following changes:1. Delete the new terms and definitions for "Active Transmission Line Right-of-way" and "Critical Clearance Zone" and revert back to a Clearance 2 requirement while replacing the IEEE 516 standard distances with the Gallet equation standard distances.2. Delete R2, M2, R4 and M4 which refer to the "Critical Clearance Zone" and rely on R5, M5, R6, M6, R7, and M7 which refer to the prevention of Sustained Outages.3. Delete R1.5 and M1.5 as a requirement and measure, but footnote the "interim corrective action process" as a best practice as was ANSI A300 in R1.1.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. Items such as the CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. Note that the SAR for this project included a list of items to be addressed in the revised standard – and these items included not only the directives in Order 693, but other issues identified during the initial implementation of the standard and during the refinement of the SAR.	
Entergy Services	Entergy requests that the proposed FAC-003-2 revision continue work on clarifying the above mentioned “Disagree” items and appreciates the consideration of the above comments in the development of the standard. A clear understanding of all standard requirements by the industry is needed to make certain field implementation is achieved and that ultimately we improve system reliability.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. Those changes were made in part for the clarity that you and others requested in order to ensure that practical field implementation may be achieved.	
Alberta Electric System Operator	The AESO is also a signatory to the joint ISO/RTransmission Owner Council Standards Review Committee comments which reflect our comments to the other questions in the Comment Form.
Response: The SDT thanks you for your comments. Please see the SDT’s responses to the ISO/RTO SRC comments.	
JEA	M5, 6 and 7 ask the entity to prove the negative. This type of evidence is problematic, and may result in nothing better than the entity

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	making an attestation that the event did not occur, thus this measure is not useful. With well over 100,000 miles of transmission covered by this standard, even six-sigma performance would result in vegetation related issues. It is unreasonable to expect zero-tolerance for vegetation events and unnecessary for the industry (and customers) to expend resources to attempt to meet this level of compliance when the transmission system is planned and operated to handle any single contingency, which means that a vegetation contact should not, in isolation, cause a major problem to the bulk power system. This standard needs work to make it clear, unambiguous, feasible and enforceable.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. **The SDT pursued an approach to develop a metric that would not have a zero-tolerance for outages. Discussion with FERC led the SDT to the conclusion that such an approach would not be acceptable.** **Changes made to the old M5, M6 and M7 in this new draft should alleviate the "prove a negative" dilemma.**	
Independent Electricity System Operator	We recommend removing the Transmission Owner as the one to define a major storm, this task should be left to an applicable regulatory body only, for consistency in assessing such an event. Also, we recommend footnote #5 specify that planned removal of vegetation by the utility is not part of the exceptions, because in our view this activity is a component of the vegetation management program and that outages should be preventable. There is a typo in R6. The numeral "4" should be superscripted.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment **The SDT has reviewed the data on vegetation related outages that TO have reported on the NERC website. There are 223 reports of outages in that data covering the period January 2004 to March 2009. The associated documentation with these events indicate that TO are supplying supportive information to indicate that the level of any disaster exclusion (including major storms) is sufficient to reasonably identify conditions that exceed design criteria. Further specific on the threshold for each disaster (or storm) would not ensure that weather data would be adequate to support each location/situation.** **Random human error in felling trees whether by loggers, homeowners or vegetation removal crews has not been associated with cascading events and remains a valid exclusion. The related safety risks and equipment damages tend to effectively self-control this type of activity.** **The typographical error in what was R6 (now R7) has been corrected.**	
Salt River Project	We question the method used in determining the clearance distances for Vegetation near Transmission Lines. First is the use of the Gallet Equation. Although the Gallet Equation is more definitive than using IEEE 516 as identified in the current standard, we have questions from an engineering prespective as to how and why this method was chosen for vegetation management. It is stated in the Technical Reference paper that the Gallet Equation is a well known method of computing the required strike distance for proper insulation coordination. It is our understanding it's purpose is for designing towers, to define the "tower window" or opening inside of a

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<tr><td></td><td>tower under normal conditions. Because this is not a method designed specifically for vegetation management, what is the basis for applying this to vegetation management? Was there, or could there be testing done? We would find it definitive to substantiate the calculated equation assertions with test data from actual energized flashover distances to vegetation. The testing ought to include dry and misting conditions at 200+ kilovolt levels on a sampling of fresh cut common vegetation types. Reputable EHV testing facilities where such tests can be performed exist within the United States and Canada. Is there additional information to clarify why this method was used to help establish clearance distances for vegetation near transmission lines? Second, it is expected that each utility needs to define their "Critical Clearance Zone".   It is outlined in the Technical Reference document how complicated it is to define this clearance area. As the conductor moves throughout its "flight path", the minimum clearance shell surrounding the conductor moves along with it. The shape and size of the Critical Clearance Zone around the conductors is irregular and will change depending on where a conductor segment is located within the span. At mid-span, where the potential for conductor movement is the greatest due to sag and wind deflection, the corresponding Critical Clearance Zone is also the largest and most irregular. With the size, shape, and area of the Critical Clearance Zone dramatically changing as one progresses along a span, identifying the precise location and boundary of the Critical Clearance Zone around the conductor in the field becomes very problematic. There are many variables that are involved at any point along a line and at any given time (loading, operating temperature, wind, maximum design rating, maximum operating loading and so on). Therefore, even if the exact size and shape of the Critical Clearance Zone is known, it becomes nearly impossible to field correlate and accurately "superimpose" the Critical Clearance Zone" around the conductor. Therefore, it seems unreasonable to expect each utility to develop and implement a defensible and auditable clearance zone.

We strongly support the development of the Technical Reference document. This would have been helpful if it was available for the first version, as it will help both utilities and auditors. We recommend that this be included in the revised version and subsequent future revisions. Please note that as FAC-003-2 goes through additional revisions prior to finalization, the Technical Reference document needs to be revised to reflect the final revisions prior to implementation.</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments. The SDT engaged TO personnel who were technical experts with significant experience and credentials in transmission line insulation coordination theory and applications. The purpose of the change to the Gallet derived distances was to provide a set of specific distances that would ensure that flashover would not occur provided those distances were not breeched under expected outdoor operating conditions. These distances are applicable to the wire with respect to structure components, vegetation or any other object at ground potential level. These values have already been proven for dry and wet conditions and need no further testing.

We have made changes in R2 and R4 that should remove the problems you have raised regarding the CCZ and how it is “nearly impossible” to apply under field conditions.</td></tr>
<tr><td>Northeast Utilities</td><td>In section 4.2.2. the time period for bringing sub 200-kV lines into compliance with the standard states a 12 month period following the designation of the lower voltage lines by the Reliability Coordinator. This can present problems if the RC designates the lines during the course of a plan year, because budgets may not have been established or funded for the additional work. It is suggested that the time period be revised to state, "by the end of the following calendar or budget year after the designation of lower voltage lines", allowing for a full calendar/budget year that can be planned and budgeted to bring lines into compliance.</td></tr>
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	There is concern over the use of the Critical Clearance Zone and making this the "bright line" where encroachment at any time under any conditions is a violation of the standard. The Critical Clearance Zone is a very detailed and calculated zone. It is improbable that an accurate determination of the Critical Clearance Zone could be made in the field. Mere encroachment should not constitute a violation. If the encorachment can be determined and corrected once found - this should be an acceptable practice. It is reasonable for utilities to spend the time, money and manpower to actively manage rights-of-way, and dealing with encroachment issues which can be identified. Many potential encroachments will not be identifiable unless one can accurately identify the Critical Clearance Zone in all cases in all areas at all times. Also, there is some concern over how the requirements are set up for violations of the Critical Clearance Zone and for sustained outages. A sustained outage due to vegetation within the active transmission right-of-way is a violation under R.5, R.6 and R.7. It is also possible that the outage is a violation of the Critical Clearance Zone under R.4. The standard implies that a utility could be assessed multiple violations of the standard for one outage with multiple penalties. Is this the desired intent? Finally, version 1 had clear requirements on what was to be reported, when the reports were required, and who was to submit reports. Is it intended that the standard rely solely on self-reports? Version 2 makes no mention of what is to be reported when a violation occurs, or of any other reports. Is reporting going to be left up to the Regional Entity to establish?
Response: The SDT thanks you for your comments. **The standard was revised to replace the Reliability Coordinator with the Planning Coordinator as the entity responsible for identifying lines sub 200 kV for which there should be a TVMP. By moving to the Planning Coordinator, there should be ample time to address the annual work plan. With its focus on "planning horizon" issues (> 1 year), the PC provides the necessary look-ahead that the RC did not. As soon as a sub-200 kV line is designated as being applicable to this standard, it is understood the subject line could potentially place the grid at risk of instability, separation or cascading. A 12 month period to perform any vegetation maintenance seems reasonable to the SDT.** **Significant changes have been made to the current draft of the Standard based upon substantive industry comment. Items such as the CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. Reporting requirements have been addressed in the compliance section of the revised Standard.**	
Hydro-Quebec Transenergie (HQT)	HQT recommends that the Standard Drafting Team review the compliance and reporting requirements for consistency and adequacy. Applicability 4.2.3 contradict first part of Applicability 4.2.1 and that of former Applicability 4.3
Response: The SDT thanks you for your comments. The SDT reviewed your concern and did not see a contradiction.	
BCTC	Any standard that is developed should not contain advisory-type language—it should be declarative in tone. For example, in R1.4, the ending clause that begins "…and may include actions…" should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program. BCTC supports the development of this white paper as a way to help ensure consistent interpretation of the standard. Perhaps the lack

Organization	Question 18 Comment
	of such a paper in the first version of the standard contributed to the varying interpretations by the auditors. The utilities understand however that this document is not a legal document and is not binding.
Response: The SDT thanks you for your comments. R1.4 has been changed to remove the advisory type language.	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Summary Considerations FAC-003-2
Second Industry Comment Period (9/10/09 to 10/24/09)

Background:

On January 14, 2010, the NERC Standards Committee endorsed the use of Project 2007-07 Vegetation Management as the prototype for the proof-of-concept for using the results-based criteria for developing a reliability standard. The results-based initiative is intended to focus the collective effort of NERC and industry participants on improving the clarity and quality of NERC reliability standards by developing performance, risk and competency-based requirements that accomplish a reliability objective through a defense-in-depth strategy, while eliminating documentation-driven requirements that do not have an impact on bulk power system reliability.

The Standards Committee directed the Vegetation Management SDT to stop work in refining its second draft of the Vegetation Management standard but to inform stakeholders on how the team had used stakeholder comments to refine the technical requirements carried over into draft 3 of the standard.

This report provides a copy of each of the questions that was posted for stakeholder comment with the second draft of FAC-003-2, and a summary indicating how the drafting team used stakeholder comments submitted in response to that question. The questions included in the second comment form provided explicit references to either background information provided in the comment form or to specific requirements or other elements in the standard and have been paraphrased here.

All questions asked and all comments provided by stakeholders have been posted at the following site:

http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

Index to Questions and Summary Responses:

Question 1

In response to industry comments, the Requirement for documentation of a TVMP was revised to clarify that the objective of the TVMP is to improve reliability by preventing Sustained Outages due to vegetation. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Second draft of proposed R1:

R1. Each Transmission Owner shall have a documented transmission vegetation management program that describes how it conducts work on its Active Transmission Line Rights of Way to prevent Sustained Outages due to vegetation, considering all possible locations the conductor may occupy under the effects of sag and sway throughout its operating range under rated conditions. The transmission vegetation management program shall: *[Violation Risk Factor – Lower][Time Horizon – Long-term planning]*

1.1. Specify the methods that the Transmission Owner may use to control vegetation.[1]

1.2. Specify a Vegetation Inspection frequency of at least once per calendar year that takes into account local[2] and environmental factors.

1.3. Require an annual work plan. An annual work plan shall:

1.3.1. Identify the applicable lines to be maintained

1.3.2. Identify the work to be performed and methods to be used

1.3.3. Be flexible to adjust to changing conditions and to findings from Vegetation Inspections. Adjustments to the plan within the year are permissible.

1.3.4. Take into consideration permitting and scheduling requirements from landowners or regulatory authorities.

1.4. Require a process or procedure for response to an imminent threat of a vegetation-related Sustained Outage. The process or procedure shall specify actions which shall include communication of the threat to the responsible control center.

1.5. Specify an interim corrective action process for use when the Transmission Owner is temporarily constrained from performing vegetation maintenance as planned.

1.6. Specify the maintenance strategies used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that Table 1 clearances in Attachment 1 are never violated. The maintenance strategies shall consider the sag and sway of the conductor throughout its operating range under rated conditions.

Summary Consideration: The vast majority of comments for this Question related to the Annual Vegetation Inspection frequency. Those commenters believed that a once/year mandate was too prescriptive and preferred to let the Transmission Owner choose a frequency.

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[1] ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

[2] Local factors include items such as treatment cycle, extent and type of treatment, and their relationship to the normal growth rate.

After reviewing Order 693 in its entirety, the SDT set the frequency at once/year to avoid a fill-in-the-blank requirement and establish a reasonable frequency for most regions. However, the SDT also made it explicitly clear that this Vegetation Inspection can be combined with other line inspections to allow maximum flexibility in meeting this requirement. The vast majority of other comments dealt with specific wording in the Draft 2, Requirement 1. In an effort to be less prescriptive, the new Draft has removed most of the text that commenters wanted changed.

Question 2

In response to industry comments, the Requirement for implementation of Imminent Threat process/procedure was revised. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Second draft of proposed R2:

R2. Each Transmission Owner shall implement its imminent threat process or procedure when the Transmission Owner has actual knowledge of such a threat, obtained through normal operating practices. *[Violation Risk Factor – Medium][Time Horizon – Real Time]*

Summary Consideration: Ninety percent of respondents agreed with Requirement 2 (Implementation of the Imminent Threat Process). No major themes of disagreement surfaced. Two respondents expressed confusion between the NERC defined term "Operating Process" and the language "operating practices" used in R2. Two respondents preferred more specificity in the requirement for audit purposes, one respondent suggested changing "actual knowledge" to "confirmed" and one respondent expressed concerns about proving a negative. Two other respondents had comments that were more appropriate for questions 1 & 4 and are answered there.

The SDT considered all comments and essentially retained all the previous language in the new draft. Of note, the term "actual knowledge" was changed to "verified knowledge" based on the guidelines for Requirements with the new standard format. This change still retains its meaning that the Transmission Owner "confirmed" the potential threat prior to initiating the Imminent Threat process.

Proposed requirement in Draft 3 of FAC-003-2:

R5. Each Transmission Owner shall take interim corrective action when it is temporarily constrained from performing planned vegetation work, where a Transmission Line is put at potential risk due to the constraint.

Question 3

In response to industry comments, the Requirement for conducting Vegetation Inspections was revised. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Second draft of proposed R3:

R3. Each Transmission Owner shall conduct Vegetation Inspections of all applicable lines (as measured in line miles) in accordance with the frequency specified in its transmission vegetation management program, unless constrained by natural disasters. When constrained by a natural disaster, the Transmission Owner shall conduct the Vegetation Inspection(s) within six months or a period agreed to by its Regional Entity, whichever is greater. *[Violation Risk Factor – Medium][Time Horizon – Operations Planning]*

Summary Consideration: Eight commenters perceived an inconsistency in the inspection frequency required between Requirement 1.2 and Requirement R3. Eleven (11)respondents felt an inspection frequency of longer than once per calendar year should be acceptable, the required frequency for inspection was unclear, or that the requirement should simply state an inspection interval of once per calendar year. Five comments (5) noted that the Requirement R3 exception for non performance due to natural disasters should be expanded, re-organized, or re-worded to be more clear or include a number of additional situations including disease or species epidemics. Several entities (6) expressed a concern over the use of the term "line miles" in the performance measures for this requirement. Finally, a few comments (2) were received that suggested the phrase "all applicable lines" be removed from the requirement.

With this new Draft, the Standards Drafting Team has removed 1.2 which eliminates any perceived confusion. After reviewing Order 693 in its entirety, the SDT re-established the frequency at once/year to avoid a fill-in-the-blank requirement and establish a reasonable frequency for most regions. However, the SDT also made it explicitly clear that this Vegetation Inspection can be combined with other line inspections to allow maximum flexibility in meeting this requirement. The FAC-003-2 Draft 3 includes a general, and more inclusive, Force Majeure section which applies to the entire Standard. The Standards Drafting Team responded to industry comments about the term "line miles". There is now more explanation of this term in the VSL for R6."

Question 4

In response to industry comments, the Requirement for preventing vegetation encroachments was revised. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Second draft of proposed R4:

R4. Each Transmission Owner shall prevent encroachment of vegetation into the Minimum Vegetation Clearance Distances (MVCD) listed in FAC-003-2 - Attachment 1 for its applicable lines as observed in real-time operating between no-load and their Rating, with the following exceptions: *[Violation Risk Factor – Medium][Time Horizon – Real Time]*

- Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from natural disasters.[3]
- Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from human or animal activity.[4]
- Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from falling vegetation.

Summary Consideration: Fifty-two percent (32 of 62) of the respondents disagreed with various aspects of Requirement 4 (Preventing Vegetation Encroachments). A major theme from 19 responses requested clarification on the fall-in tree exemption particularly when a fall-in tree may be lodged in another tree. The following six minor themes were identified:

- Requested the use of the word "critical" rather than "minimum" to aide with public perception (7 responses)
- Clarification on operating beyond emergency ratings (7 responses)
- Clarification on what is meant by "observed in real-time"(6 responses)
- Requested a force majeure exemption be added (5 responses)
- Requested observations be done by qualified observers (4 responses)
- Requested to eliminate R4 (4 responses).
- Requested an interpolation in the clearance tables for altitude(2 responses)
- Identified "Double Jeopardy" concern between Requirement 4 and the outage Requirements(1 response)

The SDT considered all comments and determined that two of these were significant enough to change the standard - the SDT combined the outage requirements (R5, R6, R7 and R8) with the encroachment requirement (R4). The SDT determined the other comments could be adequately addressed as modifications for clarity to the Technical Reference Document.

[3] Examples include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods.

[4] Examples include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation.

Question 5
In response to industry comments, the Requirement for preventing Sustained Outages due to grow-ins on IROL or Major WECC Transfer Paths was developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Second draft of proposed R5:

R5. Each Transmission Owner shall prevent Sustained Outages[5] of applicable lines that are identified as an element of an Interconnection Reliability Operating Limit (IROL) (or Major WECC Transfer Path) due to vegetation growing into a conductor operating between no-load and its Rating, with the following exceptions: *[Violation Risk Factor – High][Time Horizon – Real Time]*

- Sustained Outages of applicable lines that result from natural disasters.
- Sustained Outages of applicable lines that result from human or animal activity.

Summary Consideration: Commenters generally agreed with R5 in draft 2. The most significant issues that the SDT needed to consider were: the addition of other exclusionary conditions, the prima facie double jeopardy that exists with this requirement and R4, the lack of robust VSLs, and the need for further clarity on terms and concepts (e.g. rating, minimum).

Finally, a few commenters noted that this requirement is structured unlike other conventional NERC standard requirements in that it does not say what must be accomplished for reliability (and compliance) but rather says what must NOT be done.

The SDT considered these comments and determined that two of these were significant enough to change the standard - the SDT combined the outage requirements (R5, R6, R7 and R8) with the encroachment requirement (R4), with one combined Requirement for IROLs/Major WECC Transfer Paths and another combined Requirement for all other lines. A broadened Force Majeure section was added to the applicability section of the standard. Additionally, the new R1 and R2 in this Draft were reworded to describe what must be done.

[5] Multiple Sustained Outages on an individual line, if caused by the same vegetation, shall be considered as one outage regardless of the actual number of outages within a 24-hour period.

Question 6

In response to industry comments, the Requirement for preventing Sustained Outages due to grow-ins on non-IROL or Major WECC Transfer Paths was developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Second draft of proposed R6:

R6. Each Transmission Owner shall prevent Sustained Outages of applicable lines that are not an element of an IROL (or major WECC Transfer Path) due to vegetation growing into a conductor operating between no-load and its Rating, with the following exceptions: *[Violation Risk Factor – Medium][Time Horizon – Real Time]*

- Sustained Outages of applicable lines that result from natural disasters.
- Sustained Outages of applicable lines that result from human or animal activity.

Summary Consideration: Commenters generally agreed with R6 in draft 2. The most significant issues that the SDT needed to consider were: the addition of other exclusionary conditions, the prima facie double jeopardy that exists with this requirement and R4, the lack of robust VSLs, and the need for further clarity on terms and concepts (e.g. rating, minimum).

Finally, a few commenters noted that this requirement is structured unlike other conventional NERC standard requirements in that it does not say what must be accomplished for reliability (and compliance) but rather says what must NOT be done.

The SDT considered these comments and determined that two of these were significant enough to change the standard and have combined the outage requirements (R5, R6, R7 and R8) with this encroachment requirement (R4), with one combined Requirement for IROLs/Major WECC Transfer Paths and another combined Requirement for all other lines. A broadened Force Majeure section was added to the applicability section of the standard. Additionally, the new R1 and R2 in this Draft were reworded to describe what must be done.

Question 7

In response to industry comments, the Requirement for preventing Sustained Outages due to blowing together of vegetation and transmission line conductors was developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Second draft of proposed R7:

R7. Each Transmission Owner shall prevent Sustained Outages of applicable lines due to the blowing together of vegetation and a conductor within an Active Transmission Line Right of Way (operating within design blow-out conditions) with the following exception: *[Violation Risk Factor – Medium][Time Horizon – Real Time]*

- Sustained Outages of applicable lines that result from natural disasters or wind-blown debris.

Summary Consideration: Approximately 70% of the respondents agreed with Requirement R7. Among the commenters who disagreed, a major comment issue pertains to the definition of the Active Transmission Line ROW which is further split into two sub issues.

- The first sub issue relates to a desire for a more descriptive definition of Active ROW.
- The other sub issue suggests the elimination of Active ROW.

A minority comment area pertains to altering the requirement to become more performance based with a graduated set of VSLs.

The SDT believes that the definition of “active transmission right-of-way” is appropriate for meeting the objectives of the Standard. This topic is addressed in the ***Guideline and Technical Basis*** section of this of FAC-003-2 Draft 3. The SDT considered the other comments and determined that two of these were significant enough to change the standard - the SDT combined the outage requirements (R5, R6, R7 and R8) with this encroachment requirement (R4), with one combined Requirement for IROLs/Major WECC Transfer Paths and another combined Requirement for all other lines. A broadened Force Majeure section was added to the applicability section of the standard. Additionally, the new R1 and R2 in this Draft were reworded to describe what must be done.

Question 8

In response to industry comments, the Requirement for preventing Sustained Outages due to fall-ins of vegetation was developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Second draft of proposed R8:

R8. Each Transmission Owner shall prevent Sustained Outages of applicable lines due to vegetation falling into a conductor from within an Active Transmission Line Right of Way with the following exceptions: *[Violation Risk Factor – Medium] [Time Horizon – Real Time]*

- Sustained Outages of applicable lines that result from natural disasters or wind-blown debris.
- Sustained Outages of applicable lines that result from human or animal activity.

Summary Consideration: Approximately 78% of the respondents agreed with the Requirement R8. Among the commenters who disagree, a major comment pertains to the definition of Active Transmission Line ROW which is further split up into two sub issues.

- The first sub issue relates to a desire for a more descriptive/quantitative definition of the Active Transmission Line ROW.
- The other sub issue suggests the elimination of Active Transmission Line ROW.

A minority comment area pertains to altering the requirement to become more performance based with a graduated set of VSL's.

The SDT believes that the definition of "active transmission right-of-way" is appropriate for meeting the objectives of the Standard. This topic is addressed in the ***Guideline and Technical Basis*** section of FAC-003-2 Draft 3. The SDT considered the other comments and determined that two of these were significant enough to change the standard and have combined the outage requirements (R5, R6, R7 and R8) with this encroachment requirement (R4), with one combined Requirement for IROLs/Major WECC Transfer Paths and another combined Requirement for all other lines. A broadened Force Majeure section was added to the applicability section of the standard. Additionally, the new R1 and R2 in this Draft were reworded to describe what must be done.

Question 9

In response to industry comments, the Requirement for implementation of annual work plan was developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Second draft of proposed R9:

R9. Each Transmission Owner shall implement its annual work plan for vegetation management to accomplish the purpose of this standard. *[Violation Risk Factor – Medium] [Time Horizon – Operations Planning]*

Summary Consideration: A majority of commenters requested the restoration of the phrase "subject to legal rights," citing that doing so would improve the ability of TO's in expediting approvals for access. A few comments objected to the phrase "to accomplish the purpose of the standard" citing it was superfluous. A minority of comments pertained to the extent and effect of the phrase "within the year". Commenters pointed out that carryover work into the next year is not possible with the requirement 1.3 as written.

In response to overwhelming industry comments from the first posting of the draft standard, the SDT removed the words "within the extent of its easements and/or legal rights". The concern expressed by the first commenters pertained to avoiding the situation where the expectation is for the transmission Owner to exercise its fullest legal rights when not needed. The SDT did remove the two phrases for clarity and in keeping with the guidelines for this new form of standard development. And sections 1.3.3 and 1.3.4 which were subject to misinterpretation have been removed.

Question 10

In response to industry comments, the Requirement for the preparation of list for sub 200kV transmission lines by the Planning Coordinator was developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Second draft of proposed R10:

R10. Each Planning Coordinator shall prepare and review annually, a list of lines that are operated below 200kV, if any, which are subject to this standard. Each Planning Coordinator shall consult with its Transmission Owner(s) and neighboring Planning Coordinators to obtain input to develop the list. *[Violation Risk Factor – Lower] [Time Horizon – Long-term Planning]*

Summary Consideration: An overwhelming majority of respondents agreed with this requirement as found in the second draft. For those commenters that disagreed with the requirement, three concepts arose. First, some commenters note that a similar identification of important circuit exists in FAC-014 and as such this requirement is unnecessary. The second issue expressed involves the interaction between the TO and the PC. There was concern that the word "consult" was ambiguous and that the mere preparation of the list did not ensure that the TO would be provided the list. The last group opined that this requirement for the actual preparation of the list could be combined with the requirement to establish a methodology (R11) since either one is toothless without the other.

After reviewing these comments as well as a complete analysis of Draft 2 with respect to the guidelines for this new results-based standard development process, the Requirements dealing with the Planning Coordinator have been removed. For sub-200 kV lines, the applicability will derive from identification of Transmission Lines associated with IROLs or as Major WECC Transfer Paths - analysis already exists for both of these.

Question 11

In response to industry comments, the Requirement for the Planning Coordinator to document method for identification of applicable sub-200kV transmission lines was developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Second draft of proposed R11:

R11. Each Planning Coordinator shall develop and document its method for assessing the reliability significance of sub-200kV transmission lines whose loss would place the grid at an unacceptable risk of instability, separation, or cascading failures. *[Violation Risk Factor – Lower] [Time Horizon – Long-term Planning]*

Summary Consideration: An overwhelming majority of respondents agreed with this requirement as found in the second draft. For those commenters that disagreed with the requirement the most common concern was that a similar identification of important circuit exists in FAC-014 and as such this requirement is unnecessary or duplicative. Two minor opinions also arose, one that all lines should be included in this standard, regardless of voltage, the other that no lines operating at voltage less than 200kV should be included.

After reviewing these comments as well as a complete analysis of Draft 2 with respect to the guidelines for this new results-based standard development process, the Requirements dealing with the Planning Coordinator have been removed. For sub-200 kV lines, the applicability will derive from identification of Transmission Lines associated with IROLs or as Major WECC Transfer Paths - analysis already exists for both of these.

Question 12

The SDT received suggestions from commenters to re-sequence the requirements contained in the standard to improve the logical flow of this document. The SDT submits for consideration a proposed alternative sequence. Do you agree with the proposed alternative sequencing? If not, please recommend a suggested sequence.

Summary Consideration: With only one exception, every commenter agreed that some re-sequencing was logical and appropriate. All others that disagreed with the SDT proposal included alternative sequences.

The SDT has rewritten the Requirements and re-sequenced those remaining by Results-based -type requirements, i.e., competency-based, risk-based, or performance-based.

Question 13

The Implementation Plan proposes an effective date that gives entities at least a year to become fully compliant. Do you agree with this implementation plan? If not, please indicate what should be changed and indicate why.

Summary Consideration: Most commenters felt that the proposed implementation was acceptable. However, a sizable number found this proposed Revision to be far superior to the current in-force standard and would like the SDT to consider options to expedite the implementation. One commenter indicated they would need more time.

The SDT has chosen to retain the implementation plan, rather than attempt an expedited schedule, with FAC-003-2 Draft 3.

Question 14

Do you have further questions about the standard that the Technical Reference document (White Paper) does not clear up? If so, please elaborate and propose additions.

Summary Consideration: The most prevalent comment requested revisions to the Diagrams to eliminate trees in impermissible areas. Another popular comment dealt with a change to the Active Transmission Line Right of Way. Some commenters wanted the SDT to address the Generator Interconnection Facility (GIF) issue. And finally, a few commenters wanted a change in the phrase "operating range" and in an expanded Force Majeure section.

The SDT will modify the Drawings as requested and they will be provided in the Technical Reference Document which is planned to be posted on March 23rd 2010.

The SDT slightly modified the definition of Active Transmission Line Right of Way as shown:

Active Transmission Line Right of Way — A strip or corridor of land that is occupied by active Transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities.

The SDT is aware of the GIF issue, i.e. 200 kV, and above, circuits owned by Generator Owners which have in some instances been considered Transmission Lines. NERC created a team to address this issue for all NERC standards. The product of that team was a report of suggested changes that will be addressed by a NERC drafting team. As such this draft of FAC-003 does not include any of those recommendations as they may apply to this standard.

The phrase "operating range" has been re-written to use all NERC terms and a general Force Majeure section has been added to the applicability section of the standard.

Question 15

In response to industry comments, the applicability section is revised to replace Reliability Coordinator with Planning Coordinator. Do you agree with these changes? If not, please explain and propose an alternative.

Summary Consideration: The vast majority of commenters agreed the Planning Coordinator was the appropriate entity. A common concern of those who disagreed was that the Planning Coordinator role is not defined, not well defined, or duplicated in practice. (The SDT believes that this is registration/Functional Model problem not suited for resolution in this standard.) Only one commenter suggested the Reliability Coordinator was more appropriate for technical reasons, opining that the Reliability Coordinator was better suited to determine the importance of lines.

After reviewing these comments as well as a complete analysis of Draft 2 with respect to the guidelines for this new results-based standard development process, the Requirements dealing with the Planning Coordinator have been removed. For sub-200 kV lines, the applicability will derive from identification of Transmission Lines associated with IROLs or as Major WECC Transfer Paths - analysis already exists for both of these.

Question 16

In response to industry comments, changes were made to the definitions. Do you agree with these changes? If not, please explain and propose an alternative.
Definitions proposed with FAC-003-2 Draft 2:

> **Active Transmission Line Right of Way** — A strip of land that is occupied by active transmission facilities. This corridor does not include the inactive or unused part of the Right of Way intended for other facilities.
>
> **Vegetation Inspection** — The systematic examination of vegetation conditions on an Active Transmission Line Right of Way. This inspection may be combined with a general line inspection. The inspection includes the documentation of any vegetation that may pose a threat to reliability prior to the next planned inspection or maintenance work, considering the current location of the conductor and other possible locations of the conductor due to sag and sway for rated conditions.

Summary Consideration: A majority of commenters expressed a concern with the Active Transmission Line ROW definition ranging from unnecessary to requiring modification. Those who recommended modification cited an issue with the phrase "intended for other facilities". The belief is this phrase might preclude certain parts of a ROW from being considered inactive. A minority comment pertains to the concern of abuse in the application of the concept of Active Transmission Line ROW.

The SDT has revised the definition to attempt to address some of the concerns and in keeping with the guidelines for this new results-based standard development process.

> **Active Transmission Line Right-of-Way**
> A strip or corridor of land that is occupied by active transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities.

The majority of commenters held concern with two aspects of Vegetation Inspection definition. One concern relates to the phrase "poses a threat" and offered the alternative phrase "poses an unacceptable risk" in its place. The other concern questions the necessity of the last sentence of the definition which contains "requirement-like" text about documentation. The SDT changed the definition as shown below:

> **Vegetation Inspection**
> The systematic examination of vegetation conditions on an Active Transmission Line Right-of-Way and may be combined with a general line inspection.

Question 17

When compared to Version 1, does this proposed Version 2 of the standard either maintain or improve overall electric reliability? Please provide a technical basis for your response?

Summary Consideration: The majority of the commenters agreed that Draft 2 improved reliability. Of those who disagreed, the primary objection was the elimination of Clearance 1 and removal of the qualification requirement. The commenters cited a reduce leverage with landowners in the rationale for disagreement. A majority comment insists that the standard ought to require the application of best management practices. A majority comment insists that the standard ought to require the application of best management practices.

The SDT thanks the commenters for their support. With this new Draft, the essential concepts in Draft 2 are retained with wording better suited to the new Results-based standards development process. The SDT believes that the qualification issue is better left to a SAR team for PER standards. The SDT considered requiring ANSI A300 as part of this standard but opted to include it in the ***Guideline and Technical Basis*** section.

Question 18

Besides the comments you have already provided for the preceding questions, do you have further suggestions for improving this standard? If so, please elaborate.

Summary Consideration: Many commenters repeated concerns expressed in other sections. The most cited items were: the purpose statement, the definition of applicable lines, double jeopardy for encroachments and outages, the GO/GOP/DP line issue, the necessity for a general force majeure statement, and the reference to ANSI A300.

The SDT has replaced the purpose statement with an Objective statement retaining the same concept.

The Applicability section has been revised to address commenters concerns, except relating to Generator Interconnection Facilities. (Please see response to Question 14.)

The Double Jeopardy concerns were addressed by combining requirements to produce the new Draft R1 and R2.

A general Force Majeure section was added to the applicability section of the standard that covers all Requirements. The reference to ANSI 300 has been added to the ***Guideline and Technical Basis*** section.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on 3rd Draft of FAC-003-2 Transmission Vegetation Management — Part of Project 2007-07 Vegetation Management

The Vegetation Management Standard Drafting Team and the Standards Committee's Process Subcommittee thank all those who submitted comments on the 3rd Draft of FAC-003-2 Transmission Vegetation Management. The standard was posted for a 30-day public comment period from March 1, 2010 through March 31, 2010. Stakeholders were asked to provide feedback on the standard and its proposed format through a special Electronic Comment Form. There were 13 questions posed, and most of the questions were developed to collect stakeholder feedback on the proposed "results-based format" for the standard. There were 55 sets of comments, including comments from more than 100 different people from over 60 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

On January 14, 2010, the NERC Standards Committee endorsed the use of Project 2007-07 Vegetation Management as the prototype for the proof-of-concept for using the results-based criteria for developing a reliability standard. The results-based initiative is intended to focus the collective effort of NERC and industry participants on improving the clarity and quality of NERC reliability standards by developing performance, risk and competency-based requirements that accomplish a reliability objective through a defense-in-depth strategy, while eliminating documentation-driven requirements that do not have an impact on bulk power system reliability.

This report provides a copy of each of the questions that was posted for stakeholder comment with the third draft of FAC-003-2, a summary indicating how the drafting team or the Process Subcommittee used stakeholder comments submitted in response to that question, and the comments received. The comments may be viewed in their original format at the following site:

http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Ben Eng	New York Power Authority	NPCC	4
7.	Brian Evans-Mongeon	Utility Services	NPCC	8
8.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
9.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Michael R. Lombardi	Northeast Utilities	NPCC	1
12.	Randy MacDonald	New Brunswick System Operator	NPCC	2
13.	Greg Mason	Dynegy Generation	NPCC	5
14.	Bruce Metruck	New York Power Authority	NPCC	6
15.	Michael Schiavone	National Grid	NPCC	1
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
17. Robert Pellegrini			The United Illuminating Company	NPCC						1			
2.	Group	Jim Case	SERC OC Standards Review Group	X		X							
Additional Member			**Additional Organization**	**Region**						**Segment Selection**			
1. Gerald Beckerle			Ameren	SERC						1, 3			
2. Alvis Ianton			Southern Illinois Power Cooperative	SERC						1, 3, 5			
3. Melinda Montgomery			Entergy	SERC						1, 3			
4. Ken Parker			Entegra	SERC						5			
5. Larry Rodriquez			Entegra	SERC						5			
6. Gwen Frazier			Gulf Power	SERC						1, 3, 5			
7. Stephen Mizelle			Southern	SERC						1, 3, 5			
8. Brad Young			E.ON.US	SERC						1, 3, 5			
9. John Troha			SERC	SERC						10			
3.	Group	Louis Slade	Dominion	X		X		X	X				
Additional Member			**Additional Organization**	**Region**						**Segment Selection**			
1. Jalal Babik			Electric Market Policy	SERC						6, 5			
2. Mike Garton			Electric Market Policy	MRO						6, 5			
3. John Loftis			NERC compliance	SERC						1, 3			
4. Angela Park			NERC compliance	SERC						1, 3			
5. Aaron Jonas			Forestry	SERC						1			
4.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee										X
Additional Member			**Additional Organization**	**Region**						**Segment Selection**			
1. Chuck Lawrence			American Transmission Company	MRO						1			
2. Tom Webb			Wisconsin Public Service Company	MRO						3, 4, 5, 6			
3. Terry Bilke			Midwest ISO Inc.	MRO						2			
4. Jodi Jenson			Western Area Power Administration	MRO						1, 6			
5. Ken Goldsmith			Alliant Energy	MRO						4			
6. Dave Rudolph			Basin Electric Power Cooperative	MRO						1, 3, 5, 6			
7. Eric Ruskamp			Lincoln Electric System	MRO						1, 3, 5, 6			
8. Joseph Knight			Great River Energy	MRO						1, 3, 5, 6			

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Joe DePoorter		Madison Gas & Electric	MRO						3, 4, 5, 6			
10.	Scott Nickels		Rochester Public Utilties	MRO						4			
11.	Terry Harbour		MidAmerican Energy Company	MRO						1, 3, 5, 6			
5.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				
	Additional Member		**Additional Organization**	**Region**						**Segment Selection**			
1.	Chuck Sheppard		BPA Transmission Field Services	WECC						1			
2.	Don Swanson		BPA Transmission Line Maintenance	WECC						1			
6.	Group	Joe Spencer (SERC staff) and Jack Gardner (VMS chair)	SERC Vegetation Management Sub-committee										X
	Additional Member		**Additional Organization**	**Region**						**Segment Selection**			
1.	Randy Gann		Alabama Power Company	SERC									
2.	Gerald Beckerle		Ameren Services Company	SERC									
3.	Jeffrey Hackman		Ameren Services Company	SERC									
4.	John Neagle		Associated Electric Cooperative, Inc.	SERC									
5.	Billy George		Duke Energy Carolinas	SERC									
6.	Ron Adams		Duke Energy Carolinas	SERC									
7.	Robert Trimble		E.ON U.S. Services Inc. for LG&E & KU	SERC									
8.	Jim Case		Entergy	SERC									
9.	Ralph Hale		Entergy	SERC									
10.	Marc Tunstall		Fayetteville Public Works Commission	SERC									
11.	Reggie Wallace		Fayetteville Public Works Commission	SERC									
12.	Terry Wilson		PowerSouth Energy Cooperative	SERC									
13.	Jack Gardner		Progress Energy Carolinas	SERC									
14.	John Wolfmeyer		SERC Reliability Corporation	SERC									
15.	Jerry Lindler		South Carolina Electric & Gas Company	SERC									
16.	Richard Dearman		Tennessee Valley Authority	SERC									
7.	Group	Ben Li	IRC Standards Review Committee		X								
	Additional Member		**Additional Organization**	**Region**						**Segment Selection**			

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1. Bill Phillips			MISO	MRO						2			
2. James Castle			NYISO	NPCC						2			
3. Charles Yeung			SPP	SPP						2			
4. Matt Goldberg			ISO-NE	NPCC						2			
5. Mark Thompson			AESO	WECC						2			
6. Patrick Brown			PJM	RFC						2			
7. Steve Myers			ERCOT	ERCOT						2			
8.	Group	Richard Kafka	Pepco Holdings, Inc. - Affiliates	X		X		X	X				
Additional Member			**Additional Organization**	**Region**						**Segment Selection**			
1. Pat Byrne			Pepco Holdings, Inc	RFC						1			
2. Dave Paduda			Potojmac Electric Power Company	RFC						1			
3. Steve Benn			Delmarva Power & Light	RFC						1			
4. Olivia Watts			Atlantic City Electric	RFC						1			
5. Steve Genua			Pepco Holdings, Inc	RFC						1			
9.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				
Additional Member			**Additional Organization**	**Region**						**Segment Selection**			
1. Rebecca Spach			FE	RFC						1			
2. Katrina Schnobrich			FE	RFC						1			
3. Dave Folk			FE	RFC						1, 3, 4, 5, 6			
4. Doug Hohlbaugh			FE	RFC						1, 3, 4, 5, 6			
10.	Group	Carter B. Edge	Ad Hoc Group subteam formed to review draft standard										X
Additional Member			**Additional Organization**	**Region**						**Segment Selection**			
1. Peter Heidrich			FRCC	FRCC									
2. Pat Huntley			SERC	SERC									
3. Roman Carter			NERC	NA - Not Applicable									
4. Steve Ruekert			WECC	WECC									
5. Chris Hajovsky			RRI Energy	NA - Not Applicable									
11.	Group	Frank Gaffney	Florida Municipal Power Agency (FMPA) and Some	X		X	X	X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
			Members										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Byerle	New Smyrna Beach	FRCC	1, 3, 4
2.	Jim Howard	Lakeland Electric	FRCC	1, 3, 5
3.	Greg Woessner	Kissimmee Utilities Authority	FRCC	1, 3, 5
4.	Lynne Mila	Clewiston	FRCC	1, 3, 4
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1, 3, 4
6.	Cairo Venegas	Fort Pierce Utilities Authority	FRCC	1, 3, 4, 5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Individual	Thomas Glock	Arizona Public Service Company			X		X	X				
13.	Individual	Chip Turner	Tampa Electric Company	X		X		X	X				
14.	Individual	Stephen Mizelle	Southen Company	X									
15.	Individual	Silvia Parada Mitchell	TO/TOP	X		X		X	X				
16.	Individual	John Buckley	Omaha Public Power District	X				X					
17.	Individual	Howard Gugel	NERC Staff (12 staff members)										
18.	Individual	Gary Cox	Tucson Electric Power Co.	X									
19.	Individual	Edward Bedder	Orange and Rockland Utilities, Inc.	X		X							
20.	Individual	Greg Lange	GCPD				X						
21.	Individual	Christopher M. Crane	Westchester County Board of Legislators									X	
22.	Individual	Robert Beadle	North Carolina EMC			X	X	X					
23.	Individual	Mary Hetz	Ameren	X									
24.	Individual	James W. Smith	ITC Holding	X									
25.	Individual	Alan Gale	City of Tallahassee (TAL)					X					
26.	Individual	Virginia Cook	JEA	X		X		X					
27.	Individual	Weston Davis	Central Maine Power, Iberdrola USA	X									
28.	Individual	Eric Senkowicz	FRCC Manager of Operations										X

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
29.	Individual	Samuel Stonerock	Southern California Edison Company	X		X		X	X				
30.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				
31.	Individual	Chris Scanlon	Exelon	X		X		X	X				
32.	Individual	Jody Nelson	Ga Transmission Corp	X									
33.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
34.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
35.	Individual	Laura Zotter	ERCOT ISO		X								X
36.	Individual	Gerald T. Paulson	Western Area Power Administration - Upper Great Plains Region	X									
37.	Individual	Louis C. Guidry	Cleco	X		X		X	X				
38.	Individual	Tom Hayes	East Kentucky Power Cooperative, Inc.	X		X		X					
39.	Individual	Jack Gardner	Progress Energy Carolinas	X		X		X	X				
40.	Individual	Kevin Howard	Western Area Power Administrtaion	X								X	
41.	Individual	James Sharpe	South Carolina Electric and Gas	X		X		X	X				
42.	Individual	George Czerniewski	Consolidated Edison Company of New York, Inc.	X									
43.	Individual	Michael Pakeltis	CenterPoint Energy	X									
44.	Individual	Darryl Curtis	Oncor Electric Delivery	X									
45.	Individual	Thad Ness	American Electric Power (AEP)	X		X		X	X				
46.	Individual	Dan Rochester	Independent Electricity System Operator		X								
47.	Individual	Richard Dearman	Tennessee Valley Authority	X		X		X					
48.	Individual	Jim Fulton	BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	X									
49.	Individual	Edward Davis	Entergy Services	X		X		X	X				
50.	Individual	Jason Shaver	American Transmission Company	X									

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
51.	Individual	David Rocchio	Utility Risk Management Corporation										
52.	Individual	Earl Burnside	PPL Electric Utilities Corporation (NCR00884)	X		X							
53.	Individual	Jianmei Chai	Consumers Energy			X	X	X					
54.	Individual	John Humphrey	Nebraska Public Power District	X		X		X					
55.	Individual	Christopher M. Crane	Westchester County Board of Legislators										
56.	Individual	Mike Gammon	KCPL										

1. **In response to comments received regarding potential for "double jeopardy" and to provide differentiation between transmission lines designated as having IROLs and Major WECC transfer paths from those that are not, the SDT consolidated requirements R4 though R8 found in the August 2009 draft of FAC-003-2 into two requirements in the latest draft of FAC-003-2 (new requirements R1 and R2). Do you agree? Please explain.**

Summary Consideration: There were 43 comment forms indicating agreement with the proposed Requirement R1 and R2 and 8 comment forms indicating disagreement.

The major comment issues covered:

- The differentiation of IROL/WECC Major Transfer Path and other lines subject to this standard is defensible in the context of VRF. While vegetation outages to lines covered in R2 are preventable and as such violations, the practical impact to the BES is no different than an outage caused by other factors
- WECC Transfer Path criteria should not be included in a national standard.

The VMSDT considerations for the major comment issues are:

- The new R1 and R2 requirements have eliminated the double jeopardy problem. NERC's Standards don't allow two VRF's for the same requirement so the SDT created two requirements with different VRF's.
- The VM SDT believes that WECC criteria for Major Transfer Paths is not applicable in other RE's and assumed this to be common knowledge.

Some minor comment issues are:

- Encroachment of the MVCD should not be a violation. A sustained outage should be the grounds for a violation.
- MVCD should be defined.
- Lines which cannot impact the BES, regardless of voltage, should be exempted from the standard

The VM SDT considerations for the minor issues are:

- The team has concluded encroachment into the MVCD or 'spark-over' distance is a clear indication of improper or negligent vegetation management and further that such encroachment creates an imminent threat condition.
- MVCD is defined in both the Requirement and the Rationale.

FERC has directed the ERO to develop a methodology or test to designate "operationally significant" facilities in the March 18, 2010 Order 733. The test is intended for application in PRC-023-1; however it can be extended for FAC-003-2 use.

Organization	Yes or No	Question 1 Comment
Westchester County Board of Legislators		Do not have enough knowledge on this to provide response.

Organization	Yes or No	Question 1 Comment
Nebraska Public Power District	No	Although it does provide some flexibility to the TO, it will be difficult to determine an encroachment into the MVCD. It would easier to implement if R1 and R2 were only applicable when there was an outage on the transmission system.
Dominion	No	Dominion does not agree with the inclusion of facilities that WECC designates as 'major transfer paths' in a continent-wide standard. We suggest that, if the SDT wishes to include such reference and these facilities are meant to be treated or synonymous with either IROL or SOL, that the SDT add a proposal to adopt and define a suitable term for inclusion into the Glossary of Terms
Cleco	No	Encroachment into the MCVD should require the owner to take immediate corrective action to mitigate the threat. Such an encroachment should not be reportable as a violation. Owners may be hesitant to communicate possible vegetation threat conditions to the TOP or proper authority if they believe it will be reported as a violation. We recommend the SDT consider modifying the measure for R1 and R2 to be applicable only in the interruption of the transmission facility.
NERC Staff (12 staff members)	No	NERC Staff does not see a need to have two requirements (R1 and R2) which differentiation between transmission lines designated as having IROLs and Major WECC transfer paths from those that are not with two different Violation Risk Factors. The standard as drafted applies to all 200kv and above lines. The Violation Risk Factor for all 200 kV and above lines should be "High". R2 should be deleted and R1 should be rewritten to be:R1. The Transmission Owner shall prevent vegetation from encroaching within the Minimum Vegetation Clearance Distance (MVCD) of applicable Transmission line conductors to avoid a Sustained Outage.
Xcel Energy	No	Requirements 1 & 2 are identical except for their applicability (R1 for IROL elements and elements in the WECC Transfer Paths; R2 for all other lines =>200 KV). It is not readily apparent as to why there is a need to distinguish between the two. Referencing the Table 2 "VRF" and "VSL" matrix indicates that R1 has a "High" VRF and R2 has a "Medium" VRF. If this is the only reason, then consider adding, at a minimum, a "Rationale" box explaining that reasoning.Also, the definition of MVCD needs to be a defined term or included in R 1 & 2, e.g., "Minimum Vegetation Clearance Distance is the calculated minimum distanced stated in feet (meters) to prevent spark-over between conductors and vegetation for various altitudes and operating voltages as set forth in Table 2." See comments to # 7 and # 13.
Arizona Public Service Company	No	This is a reliability standard for 230 kV and above and those lower voltages designated by the RRO. An outage is an outage and the utility should be held accountable no matter if they are or are not designated.
SERC OC Standards Review	No	While we agree with the development of a second requirement to provide for the distinction between line segments that are critical for reliability, in R1, a regional distinction should not be embedded in a national

Organization	Yes or No	Question 1 Comment
Group		standard. We also strongly disagree that perfect compliance with R2, as stated, would improve reliability. If a line is operated to avoid projected post contingent overloads, then the tripping thereof due to any cause has no effect on BES reliability. A more prudent approach for the lines covered by R2 could be the requirement to achieve 3 sigma or 4 sigma performance over a year's time. Requirement 2, as stated, is not cost effective, and may produce an unjust and unreasonable outcome to rate payers.While this draft clarifies (from version FAC-003-1) that sustained outages are compliance violations and eliminates the "double jeopardy" which was errantly introduced in the last draft of FAC-003-2 (when sustained outages were clearly defined as compliance violations), we suggest that the team adjust R2 as previously mentioned. This draft provides a mechanism to address the difference in outages that have impact to grid reliability from those that have an impact only to local lines and associated customer reliability. The use of observed MVCD as a violation and in the violation severity level matrix: o drives the right behaviors for improving reliability (by proactively identifying and removing vegetation before it can become an imminent threat or cause an outage) o eliminates the need to perform detail engineering/surveying/theoretical calculations before cutting vegetation, o formalizes the informal interpretations that have resulted from FAC-003-1 enforcement and o allows the vegetation field operations to focus on facts and remain practical rather than theoretical.
KCPL	No	The measures for R1 and R2 are zero tolerance for encroachments into the MVCD that did not result in a "contact" with the transmission facility. Considering the substantial number of miles of transmission involved, the complexities in anticipation of vegetation growth with numerous growth variables, vegetation management limitations imposed by other regulations or requirements, and unexpected transmission events that require substantial efforts regarding physical restoration, it is not reasonable or practical for the measures here to include encroachments that do not result in an interruption of transmission service. Recommend the SDT consider modifying the measures for R1 and R2 to be applicable only in the interruption of a transmission facility.
American Transmission Company	Yes	
Bonneville Power Administration	Yes	
Central Maine Power, Iberdrola USA	Yes	
City of Tallahassee (TAL)	Yes	
Consumers Energy	Yes	

Organization	Yes or No	Question 1 Comment
Duke Energy	Yes	
Florida Municipal Power Agency (FMPA) and Some Members	Yes	
FRCC Manager of Operations	Yes	
Ga Transmission Corp	Yes	
GCPD	Yes	
ITC Holding	Yes	
Manitoba Hydro	Yes	
Omaha Public Power District	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	
Southen Company	Yes	
TO/TOP	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	
MRO's NERC Standards Review Subcommittee	Yes	1. NSRS agrees with the revisions that the drafting team has made and agrees with the combining of four requirements into two. NSRS prefers the MVCD methodology to the minimum clearance distance

Organization	Yes or No	Question 1 Comment
		methodology due to the fact that there is only one measurement to contend with versus two.2. If a company has a line with a standing IROL could they be found in violation of both the requirements R1 and R2? If so, the NSRS recommends combining R1 and R2.3. Please clarify the need for R1 and R2. Why were lines with IROL separated out from lines without IROLs?
American Electric Power (AEP)	Yes	American Electric Power agrees with this change.
IRC Standards Review Committee	Yes	Because real-time observation in Measurement 1 would require an actual measurement for comparison to Table 2 to be defendable as a violation, the SRC suggests replacing observation with measurement. The SRC would suggest deleting the phrase "to avoid a sustained outage" as that phrase does not add any clarity to either of the two requirements. There do not seem to be any encroachments that the SDT will allow. If there are encroachments that are considered allowable, who is responsible for making that consideration? And what would be considered a "sustained" outage?Minimum Vegetation Clearance Distance (MVCD) is a capitalized term used in Requirements 1, 2 and 7 but is not defined in the NERC Glossary of Terms Used in Reliability Standards nor is a definition proposed in this standards action. Either a definition should be proposed or the capitalization should be removed.
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	BGE agrees with the consolidation of R4 through R8 into two requirements in the FAC-003-2 draft.
Ameren	Yes	Creating two specific requirements removes the potential for double jeopardy.
Southern California Edison Company	Yes	SCE agrees that the consolidation of Requirements R4-R* resolves the "double jeopardy" issue.
Tampa Electric Company	Yes	The change in the draft serves to consolidate, clarify and remove the “double jeopardy” as stated above. This is an improvement in the standard.
CenterPoint Energy	Yes	The differentiation in the Violation Risk Factor for R1 versus R2 seems appropriate.
Consolidated Edison Company of New York, Inc.	Yes	The elements that comprise IROLs must be clearly communicated to each Transmission Owner and must be consistent across North America.
Orange and Rockland Utilities, Inc.	Yes	The elements that comprise IROLs must be clearly communicated to each Transmission Owner and must be consistent across North America.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	Yes	The most recent draft of the standard consolidated R4-R8 results in clearer requirements that meet the results based criteria and addresses the “double jeopardy” issue. However, there is concern with the differentiation of lines designated as having IROLs and Major WECC transfer paths from those that are not, as is proposed in the Applicability section 4.2 and subsequently in requirements R1 and R2. As stated in the background section: “This Standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this Standard is not written to address such isolated situations which have little impact on the overall Bulk Electric System.” It must be recognized that in some systems, outages on lines operated at voltages greater than 69 kV, 200 kV for example, have localized impact only and do not lead to Cascading. Concurring with the background, a line should be subject to this standard only if a vegetation related outage “could lead to Cascading”, or could have a “significant impact” on the system. It does not depend on whether it is an IROL line or not.A performance based methodology is used in NPCC to determine if an outage on a line can cause a “significant impact” on the system. The lines identified by this methodology are not identified according to their voltages, but rather by their impact on the system, regardless of the voltage.The introduction of “two” subcategories of BES - an IROL and a non-IROL - appears to just differentiate between high VRF and medium VRF. Furthermore, in the Applicability section, the IROL “variable” is mentioned only for lines operated below 200 kV. What about lines operated at or above 200 kV lines? Why not have a single Application item stating: overhead transmission lines operated at any voltage whose outages have a significant impact on the system? A Table could define what is considered “significant”.There are standards for vegetation management on the distribution system, and there are standards for higher voltage systems. This standard should focus on lines with high impact on the system when a vegetation outage occurs.Utilities will not let the vegetation encroach on other lines, but an importance will be given to vegetation management on “critical” lines for the reliability of the whole system. On other lines, if an outage occurs, it will have localized impact.A “Results-Based Reliability Standard” should first focus on the “critical” lines.If it is the intent of NERC or the industry to ensure that a vegetation outage causes no more than a fixed level of load loss, it should say so in a requirement.If the IROL “variable” is retained, identification of the transmission elements that comprise IROLs must be officially communicated to the Transmission Owners. This must be done either through a requirement in this, or another standard.
Progress Energy Carolinas	Yes	The previous version (FAC-003-1) was not developed with individual outages listed as a requirement or a violation. The previous drafts of version 2 (FAC-003-2) have improved on FAC-003-1 by defining sustained outages from within the Right-of-Way as violations. However, the recent drafts of FAC-003-2 also introduced a potential for ‘double jeopardy’ when clarifying that sustained outages and MVCD encroachments were (‘binary’) requirements/violations. This latest draft clarifies the expected performance into two concise requirements that provide for differentiation in severity levels and risk factors, eliminating the unintended

Organization	Yes or No	Question 1 Comment
		‘double jeopardy’. The inclusion of the use of observed MVCD as a violation of R1/R2 and in the violation severity level matrix drives the right behaviors for improving reliability (by proactively identifying and removing vegetation before it can become an imminent threat or cause an outage) , eliminates the need to perform detail engineering/surveying/theoretical calculations before cutting vegetation, formalizes the informal interpretations that have resulted from FAC-003-1 and allows the vegetation field operations to focus on facts (and remain practical rather than theoretical). Progress Energy believes that the R1 and R2 changes to this draft are a significant improvement over FAC-003-1. This version draft: clarifies real-time MVCD and sustained outages as a requirement; provides for differentiation between grid impacting outage events and outage events to lines primarily associated with customer reliability; introduces a performance barrier/defense that is fact based - eliminating the need to determine compliance through theoretical calculations that rely on design assumptions (e.g., mechanical behavior of aged conductor), prior design criteria/code versions (i.e., code clearances in effect at time of design) and detail site measurements (e.g., “survey” quality measurements and local environmental conditions at time of measurement/event).
JEA	Yes	The simplification and clarification improves the ability of Registered Entities to comply thereby enhancing reliability.
Independent Electricity System Operator	Yes	This change addresses the perceived “double jeopardy” risk.
Oncor Electric Delivery	Yes	This does not reduce the Standards effectiveness on the cascading issue or discount any outage on applicable lines subject to this Standard in the electric Transmission system.
East Kentucky Power Cooperative, Inc.	Yes	This draft adequately addresses the "double jepoardy" issue. The use of the Minimum Vegetation Clearance Distances simplifies recommended maintenance process for field personnel and eliminates the need to perform costly and time consuming engineering studies prior to trimming or removing vegetation.
SERC Vegetation Management Sub-committee	Yes	This draft clarifies (from version FAC-003-1) that sustained outages are compliance violations and eliminates the “double jeopardy” which was errantly introduced in the last draft of FAC-003-2 (when sustained outages were clearly defined as compliance violations). This draft provides a mechanism to address the difference in outages that have impact to grid reliability from those that have an impact only to local lines and associated customer reliability. The use of observed MVCD as a violation and in the violation severity level matrix: o drives the right behaviors for improving reliability (by proactively identifying and removing vegetation before it can become an imminent threat or cause an outage) o eliminates the need to perform detail engineering/surveying/theoretical calculations before cutting vegetation, o formalizes the informal interpretations that have resulted from FAC-003-1 enforcement and o allows the vegetation field operations to focus on facts and remain practical rather than theoretical.

Organization	Yes or No	Question 1 Comment
Western Area Power Administrtaion	Yes	This is a very efficient and logical consolidation of requirements.
Western Area Power Administration - Upper Great Plains Region	Yes	This is not a critical issue for the WAPA - UGPR.
Tennessee Valley Authority	Yes	This method effectively recognizes the difference in reliabilty risks among various lines based on their value to the transmission grid.
Entergy Services	Yes	We agree that R1 and R2 are beneficial, but believe that they should be explained in greater detail for much greater clarity to reflect their intent. Our understanding is that R1 applies to ALL IROL's and ALL Major WECC Transfer Path lines, regardless of voltage, and R2 is centered around ALL lines operated at voltages 200 kV and above but are not classified as IROL/WECC lines. Our understanding of the term "applicable line conductor" in R2 refers back to the facilities defined in Facilities - Section 4.2 and as modified by the phrase in R2: "which are not elements of an IROL and are not a Major WECC transfer path, (operating within Rating and Rated Electrical Operating Conditions)". However the appropriateness of our assumed reference back to Section 4.2 and the modification contained in R2 is not clear. It also is not clear that the term "applicable line conductor" in R2 is the same as "applicable line conductor" in R6. We suggest the term "applicable line conductor" be specifically defined as that term is intended to be applied in R2, and the term "applicable line conductor" be defined as that term is intended to be applied in R6.
FirstEnergy	Yes	We agree that the new R1 and R2 alleviate the potential double jeopardy issue as well as differentiate the high and medium risk factor transmission lines. However, we offer the following comments and suggestions for improvement:It is not clear how the Transmission Owner (TO) will determine which lines are associated with IROLs. Upon reviewing standard FAC-014 Req. R5, which requires the communication of SOLs and IROLs, the required communication of IROLs to the TO is not specified. There needs to be a tie between this standard and the FAC-014 standard, which will require a revision to FAC-014. Unfortunately, this issue will create a gap if FAC-014 is not revised and submitted to FERC in parallel with the submittal of FAC-003-2 to FERC. This may require immediate action such as an urgent action SAR or other appropriate actions.If our suggestion to revise FAC-014 is not possible at the present time, then we suggest an alternative course of action to include language in R1 of FAC-003 to aid the TO in obtaining the information regarding lines associated with IROLs. We propose adding the following sentence to R1: "The Transmission Owner can request information regarding transmission lines associated with an IROL from its Planning Coordinator."
Ad Hoc Group subteam formed to	Yes	We understand the differentiation to be around the intent that those transmission lines designated as having IROLs and Major WECC transfer paths pose a more significant threat to the reliability of the BES and that

Organization	Yes or No	Question 1 Comment
review draft standard		encroachment of the MVCD in these cases are relatively more significant. We suggest that this be clarified in the rationale.

2. **The results-based reliability standard criteria focus on striving to achieve a portfolio of performance-based, risk-based, and competency-based mandatory reliability requirements that provide an effective defense-in-depth strategy for achieving an adequate level of reliability of the bulk power system in lieu of prescriptive requirements. Consequently, the SDT revised R1 and its subparts found in the August 2009 draft of FAC-003-2 in favor of the text in the latest draft of FAC-003-2 (new requirement R3). Do you agree? Please explain.**

Summary Consideration: There were 41 comment forms that indicated agreement with revising Requirement R1 found in the August 2009 draft of FAC-003-2 in favor of the text in the latest draft (new requirement R3) and 12 forms indicating disagreement.

The major comment issues covered:

- Several respondents felt R3 lacked clarity and needed more definition. However there were a large number of commenters who specifically pointed out an appreciation for the requirement being less prescriptive and allowing the Transmission Owner flexibility in developing its program.
- Several respondents felt encroachment of the MVCD should not be a violation.
- There were several concerns raised with citing the Rating and Rated Conditions to describe the conditions the Transmission Owner should use to develop its clearances and avoid encroaching into the MVCD.
- The term “Bulk Power System” should not be used in this Requirement.

The VM SDT considerations for the major comment issues are:

- Due to the large number of respondents who expressed a positive opinion of eliminating prescriptive items in R3 using the Results-based approach the SDT felt R3 is appropriate as written.
- The team has concluded encroachment into the MVCD or ‘spark-over’ distance is a clear indication of improper or negligent vegetation management and further that such encroachment creates an imminent threat condition.
- The team has further described Rating and Rated Conditions in the Guideline and Technical Basis Section under Requirement R3.
- This term “Bulk Power System” has been removed from every instance in the Standard.

Some minor comment issues are:

- Make Standard dependant on R1 and R2 only. Remove all other requirements.
- Add NESC clearance requirements to R3.

The VMS SDT considerations for the minor comment issues are:

- One of the tenets of the Results-based framework is a set of building blocks which support each other. While R1 and R2 are the ultimate test of reliability they are an insufficient number of building blocks for an Results-based Standard.
- While adding NESC clearance requirements to R3 may clarify what is needed to develop the document, the SDT felt that Rating and Rated Conditions adequately cover this.

Organization	Yes or No	Question 2 Comment
Tampa Electric Company	No	A more in-depth technical review of this requirement is required. Our response is predicated upon the following quote from the draft standard; "...considering all possible locations the conductor may occupy assuming operation within Rating and Rated Electrical Operating Conditions."
NERC Staff (12 staff members)	No	As written, R3 does not provide enough clarity as to what should be included in a documented transmission vegetation management program. R3 should be expanded to include what should be included in the transmission plan. Such as:R3. Each Transmission Owner shall have a documented transmission vegetation management program that describes how it conducts work on its Active Transmission Line Rights of Way to avoid Sustained Outages due to vegetation, considering all possible locations the conductor may occupy assuming operation within Rating and Rated Electrical Operating Conditions. The transmission vegetation management program shall:3.1 Specify the methodologies that the Transmission Owner uses to control vegetation.[1] 3.2 Specify a Vegetation Inspection frequency of at least once per calendar year that takes into account local[2] and environmental factors. 3.3 Require an annual work plan that identifies the applicable lines to be maintained and associated work to be performed during the year. It shall be flexible to adjust to changing conditions and to findings from Vegetation Inspections. Adjustments to the plan within the year are permissible. The plan shall take into consideration permitting and scheduling requirements from landowners or regulatory authorities. It shall support the objectives of the transmission vegetation management program and utilize the methodologies outlined in the transmission vegetation management program. 3.4 Require a process or procedure for response to imminent threats[3] of a vegetation-related Sustained Outage. The process or procedure shall specify actions which shall include immediate communication of the threat to the Transmission Operator or proper operating authority. The process or procedure shall specify what conditions warrant a response.3.5 Specify an interim corrective action process for use when the Transmission Owner is constrained from performing vegetation maintenance as planned. 3.6 Specify the maintenance approach used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that Table 1 clearances in Attachment 1 are never violated. The maintenance approach shall consider the sag and sway of the conductor throughout its operating range under rated conditions.[1] ANSI A300, Tree Care Operations - Tree, Shrub, and Other Woody Plant Maintenance - Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.[2] Local factors include treatment cycle, extent and type of treatment, and their relationship to the normal growth rate.[3] The term "imminent threat" refers to a vegetation condition which is placing the transmission line at a significant risk of a Sustained Outage. Refer to Technical Reference for examples of imminent threat procedures and conditions for implementation.
Consumers Energy	No	Consumers Energy strongly disagrees with the MVCD as presented in this version of the standard. These distances do not provide an adequate safeguard to prevent outages since the conductor position relative to the vegetation is sensitive to electric load and wind at any particular moment while vegetation height is not. Measurements M1 and M2 require real-time observation of a violation of MVCD to be reportable. As

Organization	Yes or No	Question 2 Comment
		presented, vegetation growing beneath the conductor with a clearance of MVCD + 1 foot is not reportable. However, this same conductor may sag due to load increase or move due to wind displacement within hours of the real-time observation. If great enough, the sag or displacement may move the conductor in contact with the vegetation resulting in an outage just hours after being deemed compliant.At a minimum the MVCD should be designed to provide the Gallet clearance distance at maximum sag or wind displacement (whichever is greater) at all times. No matter when the line is cleared of vegetation or inspected for vegetative conditions, if the enhanced MVCD is being met an outage cannot occur until further vegetative growth occurs. Furthermore, for line clearing operations, tree crews do not and cannot determine in the field the maximum potential sag or wind displacement to know how much vegetation to clear. They require much clearer instructions with a set amount of clearing distance to obtain at the time of work. This distance must account for maximum sag, wind displacement and the Gallet distance at a minimum.
Cleco	No	Encroachment into the MCVD should require the owner to take immediate corrective action to mitigate the threat. Such an encroachment should not be reportable as a violation. Owners may be hesitant to communicate possible vegetation threat conditions to the TOP or proper authority if they believe it will be reported as a violation. We recommend the SDT consider modifying the measure for R1 and R2 to be applicable only in the interruption of the transmission facility.
GCPD	No	Grant believes that R1 and R2 should be the entire standard and the rest of the requirements should be in guidelines and supplementary materials to assist in meeting the two results based requirements. We understand that some risk-based and competency based requirements are necessary for some standards. Not this one. No grow-in caused outages is the objective. Requiring a specific plan does not show competency, it just shows you have a plan. Feels very much like the existing standards. "Show us your Documentation".
Northeast Power Coordinating Council	No	R3 specifies “...considering all possible locations the conductor may occupy assuming operation within Rating and Rated Electrical Operating Conditions.” Although both “Rating” and “Rated Electrical Operating Conditions” appear in the NERC Glossary, inspection of these definitions shows that they are very vague, and “Rated Electrical Operating Conditions” uses the word “reasonably”, a term FERC has previously indicated as being unacceptable. From a practical standpoint this seems to allow too much latitude to an entity to do the least amount of trimming and not consider the extra sag and swing caused by some of the more extreme operating conditions that “may” occur, such as loading to an STE or DAL limit during a higher velocity wind than normal, coupled with a higher ambient temperature. An entity could potentially claim that vegetation was trimmed to normal load levels, normal facility loading sag, and minimum velocity wind speed swings, and be within the tolerance of the standard as we interpret it. The Drafting Team should clarify what the expectation is with regard to line loading, sag, and swing due to wind speed and the types of operating conditions it deems to be justified to create a more exact requirement.

Organization	Yes or No	Question 2 Comment
Nebraska Public Power District	No	same concern as item 1.
Central Maine Power, Iberdrola USA	No	The TVMP must include clearances bewteen trees and conductors at time of vegetation management work.Suggest that the TVMP require the use of qualified personnel to manage this program.
Arizona Public Service Company	No	This standard lacks accountability and transparency. This is a reliability standard and the industry is to prevent outages within the active ROW. It doesn't matter if the vegetation grows-in, blows-in or falls into the conductor these are all outages. One is no less of an outage than the other one. They should be treated equally and the utility should be held accountable for lack of maintaining the transmission system.
FirstEnergy	No	We agree that the previous R1 was too prescriptive and are in favor of the new Requirement R3. However, we do not agree with all the wording of R3 as well as the Rationale box for R3. 1. Requirement R3 - The phrase "considering all possible locations the conductor may occupy assuming operation within Rating and Rated Electrical Operating Conditions" is confusing. We like the wording from the previous (Draft 2) of FAC-003-2 and suggest the following rewording of this phrase: "considering all possible locations the conductor may occupy throughout its operating range under all rated conditions."2. Rationale box for Req. R3 - We suggest removing the first sentence in the Rationale box for R3. The need to provide a basis on the intent and competency of the TO in maintaining vegetation is not explicitly stated in the requirement. Also, we are not sure what is meant by "competency". If it is referring to minimum required competencies for personnel performing vegetation management, that is outside the scope of this standard.
Ameren	Yes	
Bonneville Power Administration	Yes	
City of Tallahassee (TAL)	Yes	
Consolidated Edison Company of New York, Inc.	Yes	
Duke Energy	Yes	
Entergy Services	Yes	
Exelon	Yes	

Organization	Yes or No	Question 2 Comment
FRCC Manager of Operations	Yes	
Ga Transmission Corp	Yes	
Manitoba Hydro	Yes	
North Carolina EMC	Yes	
Omaha Public Power District	Yes	
Orange and Rockland Utilities, Inc.	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	
Tennessee Valley Authority	Yes	
TO/TOP	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	
Xcel Energy	Yes	
MRO's NERC Standards Review Subcommittee	Yes	1. NSRS agrees with the revisions to R3. With regard to operations within Ratings and Rated Conditions, are operations after a contingency considered to be within Ratings and Rated Conditions?2. Could wording be added to R3 to specify rated conditions include National Electric Safety Code conditions or assumptions?

Organization	Yes or No	Question 2 Comment
Florida Municipal Power Agency (FMPA) and Some Members	Yes	Although FMPA agrees with the intent of the Measures, FMPA is concerned that the measures M1 and M2 may not meet the purpose of the measures as stated in the latest draft version of the Standard Processes Manual, which states that that a Measure "(p)rovides identification of the evidence or types of evidence needed to demonstrate compliance with the associated requirement." Instead, M1 and M2 provide examples of evidence that would be used to determine non-compliance, not used to determine compliance.
American Electric Power (AEP)	Yes	American Electric Power agrees with this change.
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	BGE agrees with the R3 text in the latest draft of FAC-003-2.
Dominion	Yes	Dominion agrees and finds this approach superior to existing which sometimes appears to be more administratively focused.
JEA	Yes	Given the basic performance required in R1 and R2 of this version, I agree that specifics about what is included in the plan are not needed. Each entity should be encouraged to write their plan so that the occasional human errors and failures that are inevitable still lead to compliance with the performance aspects of this standard. The team should be sure that the measures do not require unfailing perfect execution of this procedure so that entities are encouraged to minimize this document.
ITC Holding	Yes	ITC feels that this draft is an improvement by clarifying the action expected by this requirement ("competency-based" program specific methodology documentation) and separating other implementing ("risk based") actions from FAC-003-1 as new requirements within this draft version. ITC also agrees with results-based reliability, a standard principle that is driven by relevant reliability requirements and measureable results rather than prescriptive requirements driven by documentation.The term "bulk power system" should not be used in the comment form or any other documentation associated with FAC-003-2.
Independent Electricity System Operator	Yes	Old Requirement R1 has been distilled down to its essential elements with the removal of the detailed sub-requirements that were previously included. This places the onus of developing an effective transmission vegetation management program (TVMP) on the asset owners where it ought to be, since they have the requisite expertise. Guidance is however provided in the Technical Reference document to assist Transmission Owners in developing a TVMP that in their view works for them, and achieves the overall objective of preventing those vegetation related outages that could lead to Cascading. By specifying the "what" appropriately and leaving the "how" to the entity, the entity is now in the best position to determine the most effective deployment of its resources for meeting the goals of the standard.

Organization	Yes or No	Question 2 Comment
CenterPoint Energy	Yes	R3 focuses on its intended impact on Sustained Outages without being overly prescriptive.
Southern California Edison Company	Yes	SCE prefers the results-based approach to crafting reliability standards because it provides utilities with the necessary flexibility to develop internal criteria based on widely accepted best practices and industry innovations.
Western Area Power Administrtaion	Yes	The old Draft 2 version of R1 was developed to give the regulatory entities substantial and tangible information from which to judge the adequacy of a TO's overall approach to program management. The old Draft 2 version of R1 was purposely crafted in this detailed manner as an alternative to attempting to manage the problematic CCZ concepts contained in Draft 1. Industry strongly rejected the CCZ management concepts contained in Draft 1 in the first comment period. It appears that the current Draft 3 version of R3 has lost some of the content needed to fully substitute for the management of Draft 1 CCZ concepts. The addition of an implementation requirement intended to measure the full execution and success of the overall management approach identified by a TO in response to the new R3 may help to address this shortcoming. As currently worded, the requirement to simply execute a flexible annual work under the new R7 in Draft 3 does appear extensive enough to fulfill this need.
Oncor Electric Delivery	Yes	The RBS defense-in-depth strategy for this Standard does provide an adequate level of reliability. The Standards purpose statement refers to the electric Transmission system and corresponding applicable lines not the BPS or BES as currently defined in the NERC glossary or being proposed (NOPR) RM09-18-000. Removing prescriptive requirements allows utilities flexibility to document their program and perform their vegetation management to achieve the goal of no outages that lead to cascading.
IRC Standards Review Committee	Yes	The SRC agrees with the intent of R3, but questions the need for inspection postponements to be limited to natural "disasters". A well-planned inspection may be delayed by a common lighting storm. While there is a need to conduct the inspections and those inspections could be done anytime within the TO's own plans - the SDT may want to modify the exception to be natural disasters or other conditions that are reported within 5 business days and agreed to as an excused condition by the Regional Reliability Organization.
Southen Company	Yes	The term “bulk power system” should not be used in the comment form or any other documentation associated with FAC-003-2.
Progress Energy Carolinas	Yes	This separates implementing actions such as inspections, annual plans and imminent threat procedures from TVMP methodology (which proves competency of the program).This draft is an improvement by clarifying the action expected by this requirement (“competency-based” program specific methodology documentation) and separating other implementing (“risk based”) actions from FAC-003-1 as new requirements within this draft

Organization	Yes or No	Question 2 Comment
		version.
SERC OC Standards Review Group	Yes	This separates implementing actions such as vegetation inspections, performing annual work plans and responding to imminent threats from the required documentation of the TVMP methodology (which proves competency of the program).This draft is an improvement by clarifying the action expected by this requirement (program specific methodology documentation requirement) and separating other implementing actions from FAC-003-1 as new requirements in this draft version.
SERC Vegetation Management Sub-committee	Yes	This separates implementing actions such as vegetation inspections, performing annual work plans and responding to imminent threats from the required documentation of the TVMP methodology (which proves competency of the program).This draft is an improvement by clarifying the action expected by this requirement (program specific methodology documentation requirement) and separating other implementing actions from FAC-003-1 as new requirements in this draft version.
Western Area Power Administration - Upper Great Plains Region	Yes	WAPA - UGPR agrees with a reliability based standard. In the plains states, we have fewer trees than many utilities, so having prescriptive requirements that assume we have lines running through forested areas seems to mandate an excessive amount of detail. We prefer to keep our program very simple -- perform periodic inspections to identify vegetation problems and then direct applicable resources in to take care of the problem. Our hope is that a results-based reliability standard will provide some flexibility for those utilities with smaller scale vegetation encroachments.
Ad Hoc Group subteam formed to review draft standard	Yes	While the new R3 is less prescriptive than the old R1, it appears to stray from criteria #4 for developing results-based standards, as described in this comment form. It appears to require only the development of a document. We understand that in some cases this cannot be avoided. We believe that this is one of those cases where the reliability objective of building competency in considering all possible locations the conductor may occupy and assuming operation within Rating and Rated Electrical Operating Conditions over-rides our reluctance in requiring a registered entity to produce a document rather than a result. We suggest that in a future revision to standard that this can be combined with R7 to create a comprehensive requirement that the entity have a vegetation management program that demonstrates it is able to perform those actions necessary to keep vegetation out of the MVCD.
KCPL	No	The measures for R1 and R2 are zero tolerance for encroachments into the MVCD that did not result in a “contact” with the transmission facility. Considering the substantial number of miles of transmission involved, the complexities in anticipation of vegetation growth with numerous growth variables, vegetation management limitations imposed by other regulations or requirements, and unexpected transmission events that require substantial efforts regarding physical restoration, it is not reasonable or practical for the measures here to include encroachments that do not result in an interruption of transmission service. Recommend the SDT

Organization	Yes or No	Question 2 Comment
		consider modifying the measures for R1 and R2 to be applicable only in the interruption of a transmission facility.

3. Do you agree with the overall layout of the proposed template? If not, please suggest an alternative layout.

Summary Consideration: Most comment forms (43 out of 53) indicated agreement with the overall layout of the proposed template. However, some expressed concerns over individual parts of the template. The Vegetation Management SDT and the Standards Committee Process Subcommittee (SCPS) appreciate the commenters' comments and suggestions.

Some commenters do not agree with grouping Measures and Requirements together on the basis that Measures are compliance related elements and hence should be grouped with the compliance elements. This suggestion was not adopted. The SCPS asked a specific question about putting the requirements and measures together, and 50 of the 52 comment forms indicated support for this change.

Some commenters proposed that the Text Boxes are not needed if standards are written clearly; others expressed a concern that the material in the text boxes may be taken as mandatory, or used by the auditors as guidelines for assessing compliance. Some suggested that it is necessary to have a clear declaration on which parts/elements in the standards are mandatory. While the rationale for a requirement may be clear to most people who are familiar with the topic addressed by the standard, as the industry grows and people unfamiliar with the industry try to understand each requirement, documenting the rationale for each requirement is expected to be useful. The Text Boxes that provide the "rationale" for each requirement and other explanatory information will remain in the body of the standard until it is balloted, but will be removed from the approved version of the standard. Their content will be moved to the Guideline and Technical Basis Section.

The subcommittee will ask that NERC's legal department to write a statement for addition to each standard to clarify which parts/elements of the standard are mandatory and enforceable and which are provided only as information.

Some commenters raised a concern over the administrative elements. Some are unsure whether or not these elements are mandatory and asked if they are mandatory, then why they are not included in the Requirement Section. These commenters suggested that if the administrative reporting is not mandatory, does it belong in the standard, or should the Rules of Procedure Section 1600 be used to collect the data or document.

Some suggested that the Guideline and Technical Basis Section does not belong to a standard; others suggested that the material in the Guideline and Technical Basis Section be moved to appendices. Some suggested that the materials in the text boxes can also be regarded as providing the 'technical basis' and as such, can also be moved to appendices. Some commenters suggested moving the Guideline and Technical Basis Section to immediately after the Requirements and Measures section for ease of reference and this suggestion was not adopted. The compliance elements of the standard include evidence retention as well as other information that is mandatory, and the SCPS believes this should appear before the elements of the standard that aren't mandatory.

Some commenters do not support moving VRFs and Time Horizons away from the Requirements to be grouped together with the VSLs. They expressed a desire to be able to see the VRF associated with each Requirement to know the violation impact. The SCPS will modify the format to put the information in both places – adjacent to the requirement and in a separate table.

Some commenters expressed a concern with putting the Development Plan, Definitions, Effective Dates and Revision History at the front end since the readers must screen through 4-5 pages before getting to the standard itself. Some commenters suggested that these housekeeping items be moved to the end, other commenters suggested putting the Background Section before the Applicability Section in the Introduction. The table with effective dates was removed as this will be challenging to keep up to date, however the other sections of the standard will remain where proposed with the exception that the Definitions Section will be moved ahead of the Background Section.

Some commenters indicated that there appears to be some redundant verbiage in the Background Section and the Guideline and Technical Basis Section. The SCPS will bring this to the attention of the VM SDT. These two sections were intended to have two distinctly different purposes – the Background Section identifies "why" the standard exists, and the Guideline and Technical Basis Section provides information that may be useful to entities in applying the standard.

Some commenters suggested using color code to differentiate between the information that is meant to be temporary and the information that is expected to stay with the standards. This suggestion was not adopted.

Organization	Yes or No	Question 3 Comment
American Transmission Company	No	a.) ATC believes that the "Guideline and Technical Basis" section does not belong within the NERC Standard. ATC feels there are parts of this section that appear to obligate the TO with additional mandatory requirements. (please refer to additional details in Question #8 below) b.) ATC believes the "Measures" section immediately following the Requirement is helpful and placement is appropriate, however, the introductory statement in R1 and R2 is poorly worded. For example, M1 currently states: " Evidence of violation of Requirement R1 is limited to:" ATC feels this is a negative approach and recommends that it be stated in a positive manner such as"" Evidence of compliance to R1 would be to: o Not have any vegetation-related Sustained Outages due to a grow-in." c.) ATC would like to clarify whether the "Rational" boxes remain within the final standard. It seems appropriate to have this information but that it would be better to have this information appear in the "Guideline and Technical Basis" section.
GCPD	No	Don't need all the extra requirements beyond R2.
Florida Municipal Power Agency (FMPA) and Some Members	No	FMPA appreciates the improvements and has additional suggestions. Please see responses to the remainder of the questions, and below, for suggestions:The evidence retention should be grouped with the Measures for ease of creating a records retention schedule for the standards and requirements.Do we really need a "Compliance Monitoring and Enforcement Processes" section of the standards? Are there any standards that don't have all of these activities?
City of Tallahassee (TAL)	No	I would delete the Rationale in favor of keeping the Guideline and Technical Basis. The Guideline appears to be more in-depth than the Rationale. This makes the Rationale unnecessary.
Northeast Power Coordinating Council	No	NPCC participating members want to thank the drafting team for the hard work devoted to developing this standard, and recognize the difficult issues of producing the first "results based" proof of concept standard and offer the following, not as criticism, but as helpful suggestions for their consideration based on a cross section of stakeholder reactions to the draft. 1) Measures are compliance related elements and should not

Organization	Yes or No	Question 3 Comment
		appear immediately after the requirements. The older template had the compliance elements grouped together in a separate section, and we suggest this continues. In the past there have been instances of RSAW (Reliability Standards Audit Worksheets) not clearly matching the standard's requirements or measures. We suggest that this initiative with a results based requirement consistently involve the development of the associated RSAWs to ensure coordination, and also that the requirement results in a performance based, competency, or risk based reliability criterion. 2) Effective dates have become a complex issue. We suggest that rather than having an effective date table in the standard, this type of information be restricted to the implementation plan and ultimately reside in a NERC relational database which is currently under discussion/development. NPCC participating members suggest that the "Effective Dates" section be replaced with "NERC BOT Adopted Date". Due to their complexities, FERC and Provincial approvals are something best left to implementation plans and databases. 3) "Rationale" boxes appearing in the Requirements section are problematic. If a "Rationale" box is required to explain part of the requirement then the requirement needs to be revised. For example, in R7 the requirement states that a TO shall execute a flexible annual vegetation management plan. Flexible in this context could have many different interpretations, yet in the "Rationale" box the use of the word flexible is clearly delineated to mean work may be deferred if not an imminent threat. In general we believe these boxes add little value, and if the requirement can't be understood without the "Rationale" then the requirement needs to be worded appropriately. Suggest these types of explanatory statements go into guidance documents, or supporting technical documents, and do not appear in the "Requirements" sections. 4) Also, there seems to be some confusion regarding the Administrative Procedure section. There seems to be requirements embedded within it, e.g. "The Transmission Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of transmission lines determined by the Transmission Owner...." Is this an enforceable aspect of the standard? If so, are there any other documents such as the NERC Rules of Procedure "ROP" or compliance related documents such as the CMEP that have to be changed? NPCC participating members recognize that this is a results based standard. Administrative requirements should be removed from the standards, and dealt with elsewhere (such as the ROP). 5) The Guideline and Technical Basis section contains valuable information, but this adds to the volume of the document. The Drafting Team should consider moving this to a separate document. In viewing the standards as a whole, the FAC-003 standard is relatively straightforward when compared to the developing of other standards such as the TPL standard. A similar approach, if applied to the TPL would result in a standard with potentially hundreds of pages. If the type of work appearing in this section is envisioned for other more complex standards such as TPL, the DT should consider separating out this section as a single supporting document. 6) Do FERC and the Provincial governmental authorities approve just the requirements in the Standard, or the whole package?
FRCC Manager of Operations	No	See responses to #8, 10, 11 and 13.
IRC Standards Review	No	The proposal to move the time horizon and the VRF to a separate independent section is not useful. Take for example R1 and R2 of the proposed standard. A careful read of the two requirements and measurements

Organization	Yes or No	Question 3 Comment
Committee		would indicate that there is no difference between them and that it would be better to have one requirement for all conductors. It is not until the reader gets to the compliance section does the VRF difference show up. There is no savings to removing the previous format's parenthetical inclusion of time horizon and VRF at the end of the requirement. The Independent Section can contain all of the proposed information but don't remove it from the requirement. The format of the standard would not be an issue if NERC would develop a standards database. Then, the database could be queried in any format the user desires.
ERCOT ISO	No	The Standard itself is several pages into the document. The VRFs/VSLs should be in the Requirements/Measures Section. The Background, Rationale, Administrative Procedures are additional information and should be located in an Appendix so it doesn't clutter the Standard.
CenterPoint Energy	No	We suggest combining and moving the Rationale, Background, Guideline and Technical Basis, and Technical Reference to a consolidated appendix because there is much duplication in the wording within each of these sections, and independently they may be misinterpreted as being an integral part of the Requirements and Measurements which they are not. The Requirements and Measurements should stand clearly on their own. The appendix should contain examples of how to meet the requirements under various circumstances. The appendix should be supplementary and optional to the Standard.It is also not clear if the Administrative Procedure is a mandatory activity. It would be helpful if the intent of this section was stated within the Standard.
NERC Staff (12 staff members)	No	We suggest using two colors for explanatory information - yellow for information that is temporary - such as the information explaining the difference between the approved and proposed definitions of "Vegetation Inspection" - and using blue for all boxes that are intended to remain in the approved standard.We feel that the Standards Committee Process Subcommittee should pursue adding a statement from NERC's legal department indicating which parts of the standard are enforceable. In the meantime, we suggest using the standard template in order to clearly define the enforceable parts of the standard. The section identified as "Guideline and Technical Basis" is not really a guideline (typically a proposed process for completing work) and is not really a "technical basis" (typically a summary of research or engineering judgment, etc. used to explain the reasoning for something). The information in this section is explaining how the drafting team expects compliance with the requirements to be measured. We suggest revising the heading to "Application Guidelines." This is the term that was originally proposed by the Results-based team and is the heading identified in the proposed Standard Processes Manual.
Ad Hoc Group subteam formed to review draft standard	Yes	
Arizona Public Service Company	Yes	

Organization	Yes or No	Question 3 Comment
Bonneville Power Administration	Yes	
Central Maine Power, Iberdrola USA	Yes	
Cleco	Yes	
Consumers Energy	Yes	
Duke Energy	Yes	
Entergy Services	Yes	
Exelon	Yes	
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
Nebraska Public Power District	Yes	
North Carolina EMC	Yes	
Omaha Public Power District	Yes	
Oncor Electric Delivery	Yes	
Orange and Rockland Utilities, Inc.	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	

Organization	Yes or No	Question 3 Comment
Southen Company	Yes	
Southern California Edison Company	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	
Xcel Energy	Yes	
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	BGE is supportive of the proposed template.
JEA	Yes	Coupling the measures and rationale with each requirement make the standard easier to follow and to implement.
Dominion	Yes	Dominion agrees, but suggests that reference(s) to figure(s) and table(s) contain links that can take reader to that section of the document. This is superior to having to scroll through document. If the reference(s) is external to this standard document, links may be harder to manage but should at least reference a common webpage(s) used by NERC for the posting of such documents.
ITC Holding	Yes	ITC feels that the overall layout of the standard (a) improves readability, (b) clarifies expectations, (c) reduces confusion associated with referencing between pages, and (4) allows for background information and the SDT rationale to accompany the standards but we would suggest locating Guideline and Technical Basis after Requirements and Measures for better reference accessibility.
MRO's NERC Standards Review Subcommittee	Yes	N/A
Tampa Electric Company	Yes	None
Western Area Power Administration - Upper Great	Yes	None

Organization	Yes or No	Question 3 Comment
Plains Region		
FirstEnergy	Yes	Overall, we like the layout of the standard, especially the Effective Date table in the front of the standard, the combination of Requirements and Measures, and the grouping of the VRF, Time Horizons, and VSL into one table. However, we would like to see a clearer delineation between the mandatory requirements and the guidance and rationale information. The standard should explicitly be clear as to what is mandatory and what is not, which may even require moving the "Rationale" text boxes out of the Requirements and Measures section. FE believes the information presented in the Rationale text boxes can be effectively covered in the "Guidelines and Technical Basis".
Western Area Power Administrtaion	Yes	The format could be enhanced by moving the Guidelines and Technical Basis section forward to be included with the corresponding Requirement, Measure, and Rationale. This would be helpful because it is awkward flipping back and forth between these two sections when trying to fully understand a requirement.
Pepco Holdings, Inc. - Affiliates	Yes	The general layout is quite effective. Still, it would be good to keep the VRFs and time horizons within the text of the requirement.
Ga Transmission Corp	Yes	The layout is adequate but many things are needing further explanation such as the MVCD.
Progress Energy Carolinas	Yes	The overall layout improves readability, clarifies expectations, reduces confusion associated with referencing between pages, and allows for background information and SDT rationale to accompany the standards (reducing the need for interpretation).
SERC OC Standards Review Group	Yes	The overall layout improves readability, clarifies expectations, reduces confusing references between pages, and allows for background and rationale to accompany standards.
SERC Vegetation Management Sub-committee	Yes	The overall layout improves readability, clarifies expectations, reduces confusing references between pages, and allows for background and rationale to accompany standards.
East Kentucky Power Cooperative, Inc.	Yes	The overall layout is greatly improved. This draft is easier to read and understand and clarifies the expected actions required in the standard.
American Electric Power (AEP)	Yes	The overall template layout is acceptable
Tennessee Valley Authority	Yes	This aids the understanding of the standard.

Organization	Yes or No	Question 3 Comment
Ameren	Yes	This draft is much more user friendly and easier to follow; appreciate the follow up information.
Consolidated Edison Company of New York, Inc.	Yes	We do believe the overall layout is effective but the SDT should consider putting the Background Section before the Applicability Section in the Introduction and also try to reduce any redundant verbiage in the Background Section and the Guideline and Technical Basis Section. A twenty-one page Standard is too lengthy and the supporting Technical Reference document properly addresses many of the issues mentioned in the Guideline and Technical Basis Section.
KCPL	Yes	

4. **Do you agree with grouping the standard development timeline (previously called roadmap) with the revision history, and the effective date(s) and putting this administrative information up front before the Introduction Section? Please explain.**

Summary Consideration: A vast majority of the comment forms (48 out of 52 who responded to this question) indicated support for grouping the Development Timeline, Revisions History and Effective Dates and putting them up front before the introduction Section.

Some commenters suggested moving this group of information to the end, other commenters suggested that the Definition Section be taken out of the group and placed just before Introduction. The SCPS does not think that moving the grouped information to the end will result in much improved readability. Readers can get to the beginning of a standard as quickly by scrolling or flipping through the pages.

The SCPS agrees with moving the Definition Section to just before the Introduction Section since Definitions are part of the balloted materials and the team adopted this suggestion. Note that after the standard is balloted, the definitions, if approved, are moved out of the standard and into the Glossary of Terms Used in Reliability Standards.

Some commenters suggested adding a table of contents. The SCPS will consider this in the next posting.

Organization	Yes or No	Question 4 Comment
IRC Standards Review Committee	No	For this standard one must read through 7 pages before getting to the reason for the posting. The administrative information should be relegated to the end of the posting not the beginning.Under exceptions in the Effective Dates section of the standard, IROLs are referenced as only being created by the Planning Coordinator. Because Reliability Coordinators must also establish IROLs per FAC-011 and FAC-014, we suggest that reference to the Planning Coordinator should be redacted and IROLs should be discussed regardless of whether the Planning Coordinator or Reliability Coordinator creates them.
Consolidated Edison Company of New York, Inc.	No	The only issue we have with the administrative information being before the Introduction Section is with the Definition of Terms Used in the Standard Section. We feel this should be part of the Introduction and not a stand alone section.
Orange and Rockland Utilities, Inc.	No	The only issue we have with the administrative information being before the Introduction Section is with the Definition of Terms Used in the Standard Section. We feel this should be part of the Introduction and not a stand alone section.
ERCOT ISO	No	This information should be located at the end so that it doesn’t distract from the main purpose of the Standard. It is cumbersome to read through several pages before getting to the actual language of the Standard.
Ad Hoc Group subteam formed to	Yes	

Organization	Yes or No	Question 4 Comment
review draft standard		
American Transmission Company	Yes	
Arizona Public Service Company	Yes	
Bonneville Power Administration	Yes	
Central Maine Power, Iberdrola USA	Yes	
City of Tallahassee (TAL)	Yes	
Cleco	Yes	
Consumers Energy	Yes	
Duke Energy	Yes	
Exelon	Yes	
GCPD	Yes	
JEA	Yes	
Manitoba Hydro	Yes	
Nebraska Public Power District	Yes	
NERC Staff (12 staff members)	Yes	
North Carolina EMC	Yes	
Omaha Public Power District	Yes	

Organization	Yes or No	Question 4 Comment
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	
Southen Company	Yes	
Tennessee Valley Authority	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	
Western Area Power Administrtaion	Yes	
Ameren	Yes	Appreciate the ability to reference up front.
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	BGE agrees with the proposed grouping and placement of these items.
Dominion	Yes	Dominion agrees that the new format is superior to the old. However, we suggest a table of contents be added to include at a minimum, sections for (1) Definitions of Terms Used in Standard (2) Effective dates, (3) Introduction, (4) requirements and measures (5) Compliance (6) Time Horizons, VRF and VSLs (7) Administrative (8+) guidelines, technical basis, tables or figures referenced in standard.
Entergy Services	Yes	Easy to follow.
Ga Transmission Corp	Yes	I do not see a problem with this change.

Organization	Yes or No	Question 4 Comment
Xcel Energy	Yes	It is acceptable to do so, however it is not clear as to how the effective date portion will be incorporated in a final version of the standard. Will there be some kind of cover page to at least indicate the standard or will it just be a small title bar at the top? (i.e. - what does page 1 of the standard look like?)
ITC Holding	Yes	ITC agrees with locating the revision history and administrative information before the introduction. This alignment improves clarity and readability by providing a single location for this information.
Florida Municipal Power Agency (FMPA) and Some Members	Yes	Just a question, when the standard becomes effective, how will it be posted? FMPA assumes that this section will move to the end of the standard instead of the front when approved.
CenterPoint Energy	Yes	No preference.
Tampa Electric Company	Yes	None
Northeast Power Coordinating Council	Yes	NPCC participating members believe this is acceptable. However our previous response to question 3 above still applies regarding the Effective Date section. It should be removed from the standard, and either appear in an implementation plan, or more effectively in a NERC relational database.
Independent Electricity System Operator	Yes	Since in this case the effective dates of all requirements are all the same, we believe the effective dates table could be significantly condensed.
East Kentucky Power Cooperative, Inc.	Yes	The format provides for better clarification and is easier to read and comprehend.
MRO's NERC Standards Review Subcommittee	Yes	The NSRS likes the way the standards is now formatted and finds it more user friendly.
American Electric Power (AEP)	Yes	These changes make sense to American Electric Power.
SERC OC Standards Review Group	Yes	This format adds clarity and improves readability.
SERC Vegetation Management Sub-committee	Yes	This format adds clarity and improves readability.

Organization	Yes or No	Question 4 Comment
Progress Energy Carolinas	Yes	This grouping improves clarity and readability by providing a single location for this information.
Western Area Power Administration - Upper Great Plains Region	Yes	WAPA - UGPR is neutral on location of these items.
Southern California Edison Company	Yes	We agree that grouping the administrative information up front is logical and makes for a cleaner presentation.
FirstEnergy	Yes	We agree with having a detailed table showing the effective dates of each requirement. However, we would like to see NERC go back into the table and specify the dates of NERC and FERC effective dates once they are known. Having the statement "1st day of the 1st quarter one year after applicable regulatory approval" in the standard does not help the user of the standard when they are working towards compliance, and requires them to go elsewhere to find when the approvals took place. All this information should be in the standard when available and NERC staff should be afforded the latitude to do so even without needing to use its Errata process. Placing the dates directly within the standard is more convenient for the end user.
KCPL	Yes	

5. Do you agree with grouping the Requirements and Measures together, in one Section now called Requirements and Measures? Please explain.

Summary Consideration: A vast majority of the comment forms (50 out of 52) indicated support for grouping the Requirements and Measures in one Section.

Some commenters suggested moving the Measures back to the Compliance Section and adding a reference to each Measure stating which Requirement it refers to. The SCPS does not think that moving the Measures back to the Compliance Section will result in any improvement in readability. Keeping the Measures together with the Requirements provides readers with a clear and easy view of what evidence needs to be provided to demonstrate compliance with the Requirements.

Organization	Yes or No	Question 5 Comment
Xcel Energy		We are indifferent as to the placement of the Measures, however it does appear to create awkward shaped paragraphs when Requirements and Measures are place around Rationale boxes.
Northeast Power Coordinating Council	No	As commented earlier in question 3, this is a compliance related issue and should be in the Compliance section. NPCC participating members believe clear concise requirements should be the focus, and inserting measures immediately after the requirements adds little value. In addition, RE compliance staffs who use the metrics find no value to moving it as well. This format would ease working with the document as a working draft, but should not be in an adopted document. Consider moving Measures back to the compliance section, and add a reference to a Measure's wording stating which requirement the measure refers to. Only adding a statement when the Requirement and Measure numbering don't line up could be considered.
Bonneville Power Administration	Yes	
Cleco	Yes	
Duke Energy	Yes	
IRC Standards Review Committee	Yes	
Manitoba Hydro	Yes	
Nebraska Public Power District	Yes	
NERC Staff (12 staff members)	Yes	

Organization	Yes or No	Question 5 Comment
North Carolina EMC	Yes	
Omaha Public Power District	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	
Southen Company	Yes	
Southern California Edison Company	Yes	
TO/TOP	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	
Western Area Power Administrtaion	Yes	
Central Maine Power, Iberdrola USA	Yes	Adds clarity between requirements and measures .
Arizona Public Service Company	Yes	APS doesn't agree with all of the requirements.
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG,	Yes	BGE agrees it makes sense to group these two sections together.

Organization	Yes or No	Question 5 Comment
CNE & CENG)		
JEA	Yes	Coupling the measures and rationale with each requirement make the standard easier to follow and to implement.
Dominion	Yes	Dominion finds this format improved over the existing as reader can more easily correlate the requirement (process/procedures) to the measure (evidence).
Exelon	Yes	Exelon agrees this is a good practice that will help ensure Requirements and Measures are aligned
Florida Municipal Power Agency (FMPA) and Some Members	Yes	FMPA agrees that grouping the Requirements and Measures together in one section is a great idea; however, to realize even more benefit, we now have the opportunity to eliminate redundant wording, e.g., M3 can be shortened to: “A documented transmission vegetation management program” and eliminate the rest of the words that are redundant with R3.
Entergy Services	Yes	Great addition and improvement!! Much clearer and easier to follow.
City of Tallahassee (TAL)	Yes	However, if you keep the Rationale text boxes, keep the Measures in the same column as the requirement. This will result in a more consistent “look and feel” to all the requirements (M3 for R3 is the example).
FRCC Manager of Operations	Yes	In addition the DT could also eliminate redundant wording in the standard requirement, e.g., M3 can be shortened to: “A documented transmission vegetation management program” and eliminate the rest of the words that are redundant with R3 or use words in the measure that refer back "to the requirement above".
ERCOT ISO	Yes	Including a specific measure with each requirement adds clarity; however, it isn’t clear whether each measure is exclusive to the requirement that it follows. Is it possible that some requirements will have multiple measures that are not listed immediately following the requirement?
ITC Holding	Yes	ITC agrees with Requirements and Measures grouped together
GCPD	Yes	Makes the standard template much easier to read and use.
Consumers Energy	Yes	Much easier to follow in this format.
Ameren	Yes	Much more user friendly to be able to see the requirement and the measurement together for clarification.

Organization	Yes or No	Question 5 Comment
CenterPoint Energy	Yes	No preference.
MRO's NERC Standards Review Subcommittee	Yes	NSRS prefers to have the requirements, measures, VRFs, VSLs and Time Horizons together instead of referencing to another page or part of the standard.
American Transmission Company	Yes	See ATC's comment on "Measures" in Question #3 above.
Tennessee Valley Authority	Yes	This aides in understanding of the standard. Grouping the VSL and VRF for each requirement along with the measurement could be beneficial too.
Ga Transmission Corp	Yes	This also is OK no problem with the layout.
Progress Energy Carolinas	Yes	This change also improves readability and improves understanding of the requirement.
SERC OC Standards Review Group	Yes	This format adds clarity and improves readability.
SERC Vegetation Management Sub-committee	Yes	This format adds clarity and improves readability.
East Kentucky Power Cooperative, Inc.	Yes	This format provides for better readability and clarification.
Tampa Electric Company	Yes	This improves the clarity and understanding to the requirements.
Independent Electricity System Operator	Yes	This is useful to avoid having to move back and forth between separate sections to find out what is needed to show that a requirement is met. We do not have a strong preference for this re-grouping however.
Western Area Power Administration - Upper Great Plains Region	Yes	WAPA - UGPR believes this makes it easier to identify the requirement and what we need to provide to demonstrate with are in compliance with the requirement.
FirstEnergy	Yes	We agree that grouping the Requirements and Measures together is convenient when utilizing the document for compliance.

Organization	Yes or No	Question 5 Comment
Consolidated Edison Company of New York, Inc.	Yes	We agree with grouping the Requirements and Measures together since it does add another level of clarifying description for our field forces who are ensuring compliance during vegetation management activities. The Measures for R1 and R2 describe evidence of violation while the Measures for the remaining Requirements R3 - R7 describe evidence of compliance. All Measures should be written consistently as either evidence of compliance or evidence of violation.
Orange and Rockland Utilities, Inc.	Yes	We agree with grouping the Requirements and Measures together since it does add another level of clarifying description for our field forces who are ensuring compliance during vegetation management activities. The Measures for R1 and R2 describe evidence of violation while the Measures for the remaining Requirements R3 - R7 describe evidence of compliance. All Measures should be written consistently as either evidence of compliance or evidence of violation.
Ad Hoc Group subteam formed to review draft standard	Yes	We agree with the understanding that the specific requirements of the standard are the enforceable elements of the standard. The rationale and measures add clarity to support a results-based requirement.
American Electric Power (AEP)	Yes	Yes, this is a more readable format.
KCPL	Yes	

6. **Do you agree with grouping VRFs, Time Horizons and VSLs together, and putting them in a table separate from the Requirements and Measures Section? Please explain.**

Summary Consideration: A vast majority of the comment forms (47 out of 54) indicated support with grouping VRFs, Time Horizons and VSLs together.

Some commenters suggested moving the VERs and Time Horizon back to the Requirements.

Some commenters agree with grouping VRFs, VSLs and Time Horizons together, but expressed a desire to also see the VRFs and Time Horizons in the Requirements as well. The SCPS adopted this suggestion in the next posting.

Some commenters suggested listing the applicable table rows with each requirement to consolidate all pertinent information with the requirement. The SPCS believes that this will convolute the Requirements and Measures Section with little added value.

Some suggested adding the penalty matrix to facilitate discussions with property owners/agencies resisting maintenance activates. The SCPS does not believe the penalty matrix is a standard element or technical reference material. This suggestion was not adopted.

Some commenters indicated that although a non-binding poll is taken of the VRFs and VSLs, it appears that the Time Horizons are part of the standard that is still subject to stakeholder ballot. Commenters suggested that the SDT should explain how this will be made clear to balloters and asked if there is an intent to modify the standards process to remove the time horizons from the portions of the standard that are subject to ballot.

In response to the above suggestions, the SCPS will retain the grouping as proposed, but will also put Time Horizons and VRFs adjacent to their associated Requirements.

Organization	Yes or No	Question 6 Comment
Pepco Holdings, Inc. - Affiliates	No	Agree that the grouping of the subject material is appropriate, but it is not necessary to also remove the VRFs and time horizons from the requirement.
JEA	No	I would prefer to have the VRF's and time horizons together with the requirements and measures section. The VSL's separate is appropriate as that is not information needed while complying, but only after a failure.
Manitoba Hydro	No	If the VRF's Time Horizons and VSLs were listed in with each requirement and measure section, it would eliminate the need for cross referencing 2 sources of information.
Oncor Electric Delivery	No	It would be nice to see the associated VRF's and Time Horizon with the requirements. No text, but referenced.
ERCOT ISO	No	The associated VRFs/Time Horizons/VSLs should be identified alongside each Requirement so that all relevant criteria for a given Requirement are organized together.

Organization	Yes or No	Question 6 Comment
IRC Standards Review Committee	No	While we agree that the grouping of the subject material is appropriate, it is not necessary to also remove the VRFs and time horizons from the requirement.
Duke Energy	No	While we like grouping VRFs, Time Horizons and VSLs together in a table, we would also like to see each VRF and Time Horizon listed with its requirement. It's a small amount of information that we think adds value in both places.
Ad Hoc Group subteam formed to review draft standard	Yes	
Ameren	Yes	
American Transmission Company	Yes	
Arizona Public Service Company	Yes	
Bonneville Power Administration	Yes	
Central Maine Power, Iberdrola USA	Yes	
Cleco	Yes	
Consolidated Edison Company of New York, Inc.	Yes	
Consumers Energy	Yes	
Dominion	Yes	
East Kentucky Power Cooperative, Inc.	Yes	
Exelon	Yes	

Organization	Yes or No	Question 6 Comment
FRCC Manager of Operations	Yes	
Independent Electricity System Operator	Yes	
Nebraska Public Power District	Yes	
North Carolina EMC	Yes	
Omaha Public Power District	Yes	
Orange and Rockland Utilities, Inc.	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	
Southern California Edison Company	Yes	
TO/TOP	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	
Western Area Power Administrtaion	Yes	
Xcel Energy	Yes	
MRO's NERC Standards Review	Yes	Again it is good to have this information together in place of referencing some other page or part of the

Organization	Yes or No	Question 6 Comment
Subcommittee		Standard.
Tennessee Valley Authority	Yes	Also please consider parsing out a copy of each VSL/VRF with in each individual requiremnt and measure part of the standard as mentioned in question 5 above.
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	BGE supports grouping VRFs and VSLs together in a separate table.
Southen Company	Yes	Consider putting the appropriate line from the table with each requirement in the body of the standard in addition to the table format. This does make the standard longer and does introduce some redundancy, but it would make each requirement easier to read and interpret on a “standalone” basis.
City of Tallahassee (TAL)	Yes	I believe this makes it easier to follow the Requirements.
ITC Holding	Yes	ITC Agree's
Florida Municipal Power Agency (FMPA) and Some Members	Yes	Much easier to find and understand
CenterPoint Energy	Yes	No preference.
Entergy Services	Yes	This grouping helps to clarify the manner in which the violations will be ranked.
Progress Energy Carolinas	Yes	This grouping improves the template used by previous versions by providing a single view of the impact and risk that has been associated with each requirement. Progress Energy believes that this change would also be improved if the applicable VRF/VSL/Time Horizon table rows were also listed with each requirement (consolidating pertinent info with the requirement). Another improvement would be including the penalty matrix (or including a URL link) to facilitate Transmission Owner discussions with property owners and other governmental agencies.
SERC OC Standards Review Group	Yes	This improves the template used by previous versions by providing a single view of the impact consideration of each requirement. An improvement would be also listing the applicable table rows with each requirement which consolidates all pertinent info with the requirement. Also, adding the penalty matrix would facilitate discussions with property owners/agencies resisting maintenance activates.

Organization	Yes or No	Question 6 Comment
SERC Vegetation Management Sub-committee	Yes	This improves the template used by previous versions by providing a single view of the impact consideration of each requirement. An improvement would be also listing the applicable table rows with each requirement which consolidates all pertinent info with the requirement. Also, adding the penalty matrix would facilitate discussions with property owners/agencies resisting maintenance activates.
GCPD	Yes	This is audit stuff that does need to stay together.
Northeast Power Coordinating Council	Yes	This is consistent with FERC's determination that these are compliance elements and not part of the standard requirements. It will also assist with compliance determinations.
Western Area Power Administration - Upper Great Plains Region	Yes	WAPA - UGPR is neutral on location of these items.
FirstEnergy	Yes	We agree with grouping these items together. It may also be beneficial to include links directly in the table to explanations of VRFs, Time Horizons, and VSLs so that someone unfamiliar with, for instance, what a "Long-Term Planning" horizon means, they could look it up.
NERC Staff (12 staff members)	Yes	We agree with the idea behind the grouping. However, according to the Reliability Standard Development Procedure - Version 7, although a non-binding poll is taken of the VRFs and VSLs, it appears that the Time Horizons are part of the standard that is still subject to stakeholder ballot. The SDT should explain how this will be made clear to balloters. Is there intent to modify the standards process to remove the time horizons from the portions of the standard that are subject to ballot? This issue needs to be addressed by the Standards Committee Process Subcommittee.
Tampa Electric Company	Yes	With all of the VRFs, Time Horizons and VSLs grouped together it facilitates the overall understanding of these factors as they relate to the standard.
Ga Transmission Corp	Yes	Yes this was a good change.
American Electric Power (AEP)	Yes	Yes; this format is more user-friendly.
KCPL	Yes	

7. **Do you agree with the insertion of text boxes, where necessary, to help readers better understand the basis of the Definitions and Requirements? Please explain.**

Summary Consideration: The majority of comment forms (43 out of 54) agree with the insertion of text boxes.

Some commenters disagree with the insertion as the material in the text boxes will be subject to FERC's review and approval.

Other commenters raised a concern that the materials may become pseudo requirements; others are concerned that the material in the text boxes is also mandatory, or may be used by auditors as guidelines to assess compliance.

Some believed that text boxes are not necessary given there is a Guideline and Technical Basis Section. Some suggested removing the text boxes and moving the material to the Guideline and Technical Basis Section.

Some commenters indicated that some text boxes can be temporary (for example, those associated with a definition). More clarity is needed to distinguish this type of text box in the drafting stage, with the expectation that they will be removed after a standard is approved and the definition becomes effective (and removed from the standard).

The SCPS appreciates these comments and the commenters' concerns. The SCPS agreed to post the text boxes with the working document but move the text boxes into the Guideline and Technical Basis Section to support the standard until it is balloted, but will be removed from the approved version of the standard before it is submitted for adoption and filing with regulatory and governmental authorities. Their content will be moved to the Guideline and Technical Basis Section. The material in the Guideline and Technical Basis Section is intended to provide guidance but is not intended to expand on any of the requirements and is not intended to include any mandatory performance. A legal statement will be added to the standard to make this clear.

Organization	Yes or No	Question 7 Comment
Exelon	No	Additional clarifications should be included in appendices or reference documents. Including them with the requirements and measures will cause confusion concerning what the compliance obligation is. This will introduce uncertainty to the compliance monitoring process.
American Transmission Company	No	Although the test boxes provide some addition help, ATC believes that these text boxes should appear in the Guideline and Technical Basis section and that whole section should appear in a companion document to the standard but not be included as part of the standard. Also, see ATC's comment on Rational in Question #3 above.ATC believes that guidance information should not be reviewed and approved by FERC and the inclusion of such information within the standard opens this language up to FERC's oversight and approval.
Northeast Power Coordinating Council	No	As stated in question 3 above, NPCC participating members believe crisp, clear results based requirements require no further explanation. Requirements must be written so they are clearly understood. Text boxes clutter up the standard. Questions could arise if these add "pseudo" requirements to the standards, and there is any inconsistency in what is stated about requirements. NPCC strongly suggests their removal in favor of

Organization	Yes or No	Question 7 Comment
		clear, measurable, and high quality results based requirements.
City of Tallahassee (TAL)	No	I would delete the Rationale in favor of keeping the Guideline and Technical Basis. The Guideline appears to be more in-depth than the Rationale. This makes the Rationale redundant and unnecessary.
CenterPoint Energy	No	It is not clear how the information in the text boxes will be used to determine compliance with the Requirements and Measures. It appears that in the Definition of Terms Used in Standard section that the text boxes add to the definitions or are footnotes to historical information. The Definitions should stand on their own and be robust enough to ensure they are helpful in determining compliance with the Requirements and Measures. In the Requirements and Measures section, the text boxes appear to contain partial information from the Guideline and Technical Basis, and Technical Reference. In all cases the information is not helpful and provides incomplete information. The text boxes should be deleted and pertinent information to compliance should be incorporated into the Definitions, Requirements, and Measures. Any explanatory text or examples should be moved to an appendix as supplementary and optional to the Standard.
ERCOT ISO	No	It is not clear whether the information in the text boxes is “For Information Only.” While the additional information may be helpful, it appears to add sub-requirements within the Standard. This information could be included under a “Rationale” section in an Appendix. However, if the information clouds the purpose of the Requirements or dictates how to comply, then it should be eliminated completely.
Consumers Energy	No	Not necessary given the “Guidelines and Technical Basis”.
Nebraska Public Power District	No	Text boxes and other supporting information are a benefit to the reader as a clarification guide, but should be placed in something other than the Standard.
IRC Standards Review Committee	No	The concept of text boxes needs further discussion. The idea of using text boxes for clarity and explanation is valuable, but is the material in the text box mandatory? If it includes mandatory material than it is not a good idea - all mandatory requirements must be in the requirement. If the text boxes are retained to explain how a phrase is being used (e.g. to make clear what compound actions apply to what compound time frames), then yes, this approach can be invaluable.
Cleco	No	The inclusion of the text implies additional requirements. Keep quidance to a separate paper.
Arizona Public Service Company	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 7 Comment
Consolidated Edison Company of New York, Inc.	Yes	
Duke Energy	Yes	
FRCC Manager of Operations	Yes	
Manitoba Hydro	Yes	
Omaha Public Power District	Yes	
Oncor Electric Delivery	Yes	
Orange and Rockland Utilities, Inc.	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
Southen Company	Yes	
Tennessee Valley Authority	Yes	
TO/TOP	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	
MRO's NERC Standards Review Subcommittee	Yes	1. We agree. The rationale boxes will cut down on interpretations. 2. Are the rationale boxes part of the approved standards for which registered entities will be audited. Are the rationale boxes federal law?3. Under R3, a reference to the National Electric Safety Code in the rationale box would be helpful. (The goal is to

Organization	Yes or No	Question 7 Comment
		verify that utilities will not be held in violation of this standard when operating beyond the NESC conditions.)
North Carolina EMC	Yes	Additional background in the test boxes is very helpful.
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	BGE agrees this would help clarify the basis of the Definitions & Requirements.
Dominion	Yes	Dominion agrees, but suggests that reference to figure(s) and table(s) contain links that can take reader to that section of the document. This is superior to having to scroll through document. If the reference(s) is external to this standard document, links may be harder to manage but should at least reference a common webpage(s) used by NERC for the posting of such documents.
Xcel Energy	Yes	However, the boxes should be adding clarity, not "defining' terms or stipulating further requirements/criteria that must be met. See MVCD in R1 & R2 and the incorporated Table 2, and comments to #1 & #13 in this form. The standard should be able to convey the requirements without the text boxes or, if the text boxes are used, the purpose and legal import of such boxes should be clarified. Further, it should be clarifed that for text boxes that provide examples (e.g., the boxes on page 2 in the definitions section), such boxes should clearly state that the examples are in no way limitations.
Ga Transmission Corp	Yes	I do like the text boxes.
ITC Holding	Yes	ITC agrees, but would like to suggest that the text boxes include additional pertinent information from the Technical Reference that would be helpful as reliability talking points to the public. Example: (R3): The following is a sample description of one combination of strategies which may be utilized by a Transmission Owner. A Transmission Owner's basic maintenance approach could be to remove all incompatible vegetation from the right of way if it has the right to do so and has no constraints
Ameren	Yes	It's helpful to understand the SDT's logic for requirements, clarification is always appreciated.
GCPD	Yes	May help in cutting down the volume of SAR interpretation requests.
Central Maine Power, Iberdrola USA	Yes	R3 - this may be a good place to describe clearances at time of vegetation management work
Florida Municipal Power Agency	Yes	The clarification is important and will reduce the number of requests for interpretation if interpretation is already provided to some extent. Just a caution about how the text boxes will be used in the audit process,

Organization	Yes or No	Question 7 Comment
(FMPA) and Some Members		clarification concerning their use during compliance monitoring would be great.
NERC Staff (12 staff members)	Yes	The explanatory information posted with the proposed definitions, like the definitions, is only relevant to this standard, and some of the information is only relevant to the point where the definition becomes enforceable. What is the expectation for what will happen to this information in the future? We suggest that the text boxes associated with requirements include a reference to that requirement. (Change “Rationale” to “Rationale for R1”)
Western Area Power Administrtaion	Yes	The format could be enhanced by moving the "Guidelines and Technical Basis" section forward to be included with the corresponding Requirement, Measure, and Rationale. Perhaps the "Guidelines and Technical Basis" could also be combined with the corresponding "Rationale" text box. This would be helpful because it is awkward flipping back and forth between these two sections when trying to fully understand a requirement.
SERC OC Standards Review Group	Yes	This format adds clarity and improves readability.
SERC Vegetation Management Sub-committee	Yes	This format adds clarity and improves readability.
East Kentucky Power Cooperative, Inc.	Yes	This format is simpler, easier to read, understand and implement.
Progress Energy Carolinas	Yes	This format provides clarity and improves readability. Progress Energy believes that having SDT basis information for a requirement in the standard will reduce the need for interpretation and improve the interpretation process for a requirement, if necessary.
Tampa Electric Company	Yes	This improves the clarity and understanding to the requirements.
American Electric Power (AEP)	Yes	This is a good change.
JEA	Yes	This is extremely helpful in understanding the intent of the requirement
Western Area Power Administration - Upper Great Plains Region	Yes	WAPA - UGPR believes that the expanations within the text boxes provided additional useful information.

Organization	Yes or No	Question 7 Comment
Entergy Services	Yes	We agree that text boxes being used for additional clarity is a benefit if used in a correct and clear manner. It needs to be specifically stated in the document that the text boxes are to be used for reference only, entities will not be required to specifically follow the language in the Rationale box, and that each utility should specify their own process for addressing each Requirement. For example....the Rationale box for R4 states that "Verified knowledge includes observations by journeyman lineman, utility arborist, or other qualified personnel.......". Our process will specify exactly who that qualified personnel is (Transmission Specialist or another qualified Entergy Employee in the Transmission Vegetation Group, for example). We will specify this in our internal processes.
FirstEnergy	Yes	We agree that text boxes can be useful for requirements and definitions. However, the SDT may want to consider eliminating the text boxes since this information is already provided in the Guidance and Technical Basis section. Also, we have the following additional comments:General:1. With respect for the rationale text boxes for definitions, it is not clear if these boxes will be retained once the definitions are moved out of the standard and added to the NERC Glossary.2. The rationale text boxes can be beneficial for the requirements, but some of the text boxes in this current draft of FAC-003-2 seem to include prescriptiveness that is not found in the requirement. An example is in the text box for Req. R4, which implies timeliness of notification of an imminent threat with the use of the word "rapid". In the case of R4, the requirement should state that notification be carried out immediately (see our suggested rewording of R4 in Question 13). 3. Although these text boxes are not enforceable for compliance, we are not convinced that an auditor will view this as simply guidance.Specific:1. Definition for Active Transmission Line ROW - Example 3 of Inactive ROW - Consider removing this example; situations where vegetation is left unmanaged on portions of the ROW where double-circuit structures exist with only one circuit strung with conductors poses an unnecessary increased risk for vegetation related outages. 2. Rationale box for Req. R3 - See our comments in Question 23. Rationale box for Req. R4 should be revised to state: "To ensure rapid notification of the responsible control center when an occurrence of an imminent threat condition is verified. Evidence of verified knowledge includes observations by journeyperson, lineperson, utility arborist, or other qualified personnel, or a report verified by these personnel. This notification allows the responsible control center to take the appropriate action until the threat is relieved. Appropriate actions may include a temporary reduction in the line loading or switching the line out of service."4. Rationale box for Req. R5 - (1) The last statement of this box seems incomplete. It should be revised to state: "This requirement is not intended to address situations where the transmission line is not at immediate risk and the work event can be rescheduled or re-planned using an alternate work methodology."; and (2) We suggest revising the first statement to "Legal actions filed by property owners, easement restrictions and other events...."
Southern California Edison Company	Yes	We agree that the insertion of text boxes aids readers in understanding the basis for the Definitions and Requirements.

Organization	Yes or No	Question 7 Comment
Independent Electricity System Operator	Yes	We agree that the side-bars give useful contextual information that is not part of standard. This is good and avoids the reader's attention being completely redirected to a reference document when seeking clarification of the intent of a requirement. We believe however that these text boxes should be used sparingly and the content should also be brief to minimize possible distractions to the reader.It should also be made clear in the standard that these text boxes are not intended to impose additional requirements and in the event of any perceived conflict, the text of the requirement will take precedence.
South Carolina Electric and Gas	Yes	We agree, however we would like clarification on whether entities can be held accountable for rationale portions of the standard as they are for interpretations that are added to a standard.
Ad Hoc Group subteam formed to review draft standard	Yes	We understand this question to refer to the "rationale" text boxes in this standard. Additional information such as this is useful to the entity in explaining and clarifying the understanding of the drafting team in articulating the requirement and thus supports a fuller understanding of the entity in achieving compliance with the requirement.
KCPL	No	I like information that helps to "guide" and "provide guidance", however, we already having trouble with information from FAQ's, White Papers, and other guiding documents creeping into the requirements by auditing teams. The inclusion of "guiding information" in the text of the Standard itself may promote adding to requirements. Although helpful, I recommend removing this text from within the body of the Standard.

8. Do you agree with the addition of a Guideline and Technical Basis Section to place technical materials and other related information that assists entities in understanding how to comply with the standard but does not contain mandatory actions/activities? Please explain.

Summary Consideration: Most of the comment forms (38 out of 54) indicated agreement with the addition of the Guideline and Technical Basis Section.

Some commenters expressed a concern over how the materials contained in this Section may be used in compliance monitoring and enforcement.

Some commenters suggested that it should be expressly stated that this section is for information purposes only and is not part of the Standard Requirements. They further suggested compiling all of the "Information Only" materials into an Appendix as a preferred alternative. Others suggested that guideline materials be moved into a separate document.

Some commenters suggested that while this Section contains useful materials, NERC should consider developing a separate set of Guideline documents to afford the industry a knowledge base that is not directly sanctionable for non-compliance.

Some commenters expressed a concern that being located within the standard, the Guideline Section will imply additional requirements for mandatory compliance, or get used by auditors as compliance issues.

The SCPS assesses that the industry likes the idea of having technical guidelines for standards. Guideline materials, whether they are put in a separate document or included in a standard, can be used by anyone to assess compliance with standards. Putting them outside of the standard does not eliminate this possibility.

The material in the Guideline and Technical Basis Section is intended to provide guidance but is not intended to expand on any of the requirements and is not intended to include any mandatory performance. A legal statement will be added to the standard to make this clear. The SCPS believes that as long as it is made clear that only the requirements and provision of evidence are mandatory, any supporting materials can be provided in a standard to aid readers better understand the standard without binding them to complying with the supporting materials. The intent of the description of the elements of a standard in the proposed Standard Processes Manual is to make it clear that there is a distinction between the enforceable sections of the standard and the compliance and supporting information sections of the standard.

Organization	Yes or No	Question 8 Comment
Florida Municipal Power Agency (FMPA) and Some Members	No	Although FMPA agrees that a Guideline and Technical Basis document is important, FMPA has concerns about how this section might be used in compliance monitoring and enforcement. For instance, R4 has a time requirement somewhat embedded in the Guideline and Technical Basis that is not in the requirement in the standard: "The imminent threat process should be implemented in terms of minutes or hours as opposed to a longer time frame for interim corrective action plans". How many minutes or hours? This adds ambiguity to the standard. If a time limit is desired, it should be in the requirement. There are other examples of items that could be interpreted as requirements in the Guidelines. It should be made clear what the purpose of the Guidelines is in compliance monitoring and enforcement. FMPA suggests publishing two documents in the same fashion that the Functional Model has two documents, one for the standards (e.g., the requirements), and another for technical guidance to the standards (e.g., the Guideline and Technical Basis section) to

Organization	Yes or No	Question 8 Comment
		parallel the structure of the Functional Model and Functional Model Technical Document, which will help make the distinction between CMEP and guidance more distinct.
American Transmission Company	No	ATC disagrees with the above statement that it only assists in understanding how to comply. ATC believes that parts of this section are written so they could be interpreted to contain mandatory actions/ activities. To demonstrate, see example on pg.15, R4, 2nd paragraph states...Two key elements of an acceptable imminent threat procedure are outlined below:..........) It should not be more than a preferred method for implementation or supporting how the TO can meet the standard. NERC needs to clarify how this section was intended to be used. (This as written could become part of a Compliance Audit process)Also, refer to ATC's comment on this section in Question #3 above.
Bonneville Power Administration	No	Consider referencing ANSI A300 part 7 as best management practices for R3. It is currently referenced in the White Paper, and would lend more credibility to the standard if it was inserted in the text box for R3.
ERCOT ISO	No	For the same reasons stated in the comments to Question 7, it should be expressly stated that this section is for information purposes only and is not part of the Standard Requirements. Compiling all of the "Information Only" materials into an Appendix would be the preferred method of organization.
Northeast Power Coordinating Council	No	NPCC participating members do not believe that publishing more information as part of the standard is appropriate. For the same reasons as stated in the preceding response related to "Text Boxes" in question 7, any inconsistency may result in a conflict with a requirement. The information in the Guideline and Technical Basis section is valuable, however, and should be available to the industry in the form of guidelines. NPCC participating members suggest that NERC assemble a comprehensive set of "Guideline" documents into one bookmarked pdf publication to be updated as standards change. This will afford the industry a knowledge base that is not directly sanctionable for non-compliance, but a set of industry best practices, background, and reference for the standards development activities. Also, concern exists that FERC and Provincial governmental authorities will have jurisdiction over "Guidelines", and when the standard is approved it will become a mandatory "rule".
Nebraska Public Power District	No	Same as item 7.
CenterPoint Energy	No	See answer to Q3.
GCPD	No	Should be separate documents. If located with the standard it will get used by the auditors as compliance issues. NO matter how much text you provide to the contrary it will become part of the standard over time.

Organization	Yes or No	Question 8 Comment
Consolidated Edison Company of New York, Inc.	No	Since the SDT has developed a complete Technical Reference Document for this Standard, there seems to be redundancy with the Guideline and Technical Basis Section. This Standard has become too lengthy with all of the additional details and information that has been added. We prefer to have a shorter Standard and a more detailed stand alone supporting reference document.
Orange and Rockland Utilities, Inc.	No	Since the SDT has developed a complete Technical Reference Document for this Standard, there seems to be redundancy with the Guideline and Technical Basis Section. This Standard has become too lengthy with all of the additional details and information that has been added. We prefer to have a shorter Standard and a more detailed stand alone supporting reference document.
Cleco	No	The inclusion of the text implies additional requirements. Keep quidance to a separate paper.
IRC Standards Review Committee	No	This change also requires some additional explanation. What level of importance will be given to such materials? If an SDT inserted a Best Practices document, does that allow auditors to refer to that document for purposes of holding an entity non-compliant? Are these materials there to help entities who do not know how to comply? If these materials are self-help guides, then it would be better to include them as URL references that are stored in the NERC library. That way there can be not confusion about whether the material is there as a self-help guide, or as a reference for auditors.
FRCC Manager of Operations	No	We agree that this is valuable information and important to convey with the standard. This should be a separate companion document balloted, approved and posted with the standard but not be a part of the standard.
TO/TOP	No	We agree that this is valuable information and important to convey with the standard. This should be a separate companion document balloted, approved and posted with the standard but not as part of the standard.
SERC OC Standards Review Group	No	We recommend that the text “grid reliability” be substituted for “Bulk Electric System” on page 6 of the draft.The inclusion of non-mandatory guidelines in a standard that will ultimately be approved by FERC gives undue credence to “guidelines” that will lead undoubtedly to mis-application by future compliance auditors. We suggest separation of this information from the mandatory reliability standard that will be filed at FERC. It could be held in a repository on the NERC website.
Arizona Public Service Company	Yes	
Central Maine Power, Iberdrola	Yes	

Organization	Yes or No	Question 8 Comment
USA		
Consumers Energy	Yes	
Duke Energy	Yes	
Exelon	Yes	
Manitoba Hydro	Yes	
North Carolina EMC	Yes	
Omaha Public Power District	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	
Tennessee Valley Authority	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	
Tampa Electric Company	Yes	Aids in improved understanding of FAC-003-2.
FirstEnergy	Yes	Although we agree that guidelines are good to have and agree that having them in the body of the standards is convenient, we question how this section will be viewed from a compliance standpoint. We understand this section is not intended to be mandatory, but does that mean that regulatory authorities will only approve the other sections of the standard and not this section? Also, it should be clear and explicitly stated in the lead-in

Organization	Yes or No	Question 8 Comment
		to this section that this is guidance which is not mandatory and enforceable. Additionally, terms such as "shall", "should", and "require" should not be used in the guidance section because the information presented in this section could be construed as mandatory by an auditor. An example of this is in the guidance information for Requirement R7 which states "Documentation is required when the annual work plan is adjusted...". This mandatory-type language should not be included in the Guidelines section.
MRO's NERC Standards Review Subcommittee	Yes	Another good addition to the standard and will help clarify parts of the standard without referring to another document or set of guidelines.
Southern California Edison Company	Yes	Assuming that the "Guideline and Technical Basis Section" will be retained and revised in future revisions to the standard, such information should prove very useful.
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	BGE agrees with the addition of a Guidance & Technical Basis section.
JEA	Yes	Having the information in the same document makes the information more accessible to the entity attempting to comply with the standard.
Ga Transmission Corp	Yes	I do however believe that each utility should have the flexibility to manage there program the way they feel is the most effective method. I do not want the technical basis section to limit options. Should this be in a white paper format?
East Kentucky Power Cooperative, Inc.	Yes	I have no preference one way or the other on this issue.
ITC Holding	Yes	ITC agrees with Guidelines and Technical Basis section, but recommend including useful Technical Reference actions and activities that would support defense-in-depth strategy. We also feel that to avoid any confusion with the applicability section and interpretations in the future, any references to the Bulk Electric System in the standard sections and guidance/technical reference document should be reviewed and changed.
Entergy Services	Yes	Language should be added to the Guideline and Technical Basis Section to clarify or re-state that this section is for assisting entities in understanding how to comply with the standard but does not contain mandatory actions/activities, and a statement that entities are not required to use the information in the Guideline and Technical Basis Section.

Organization	Yes or No	Question 8 Comment
Western Area Power Administrtaion	Yes	The format could be enhanced by moving the "Guidelines and Technical Basis" section forward to be included with the corresponding Requirement, Measure, and Rationale. Perhaps the "Guidelines and Technical Basis" could also be combined with the corresponding "Rationale" text box. This would be helpful because it is awkward flipping back and forth between these two sections when trying to fully understand a requirement.
NERC Staff (12 staff members)	Yes	There is no language in the body of the standard to clarify that the information in the Guideline and Technical Basis Section of the standard is not subject to enforcement. We suggest revising the heading to “Application Guidelines.” This is the term that was originally proposed by the Results-based team and is the heading identified in the proposed Standard Processes Manual.
SERC Vegetation Management Sub-committee	Yes	This format adds clarity and improves readability.
Xcel Energy	Yes	This is all good information to add a depth of understanding for the user. It's not clear as to how modifications to the Guideline and Technical Basis would come about - it is the same as the standards revision process? Does this section replace the white paper? Will it actually be deemed to be part of the Standard? We are curious as to the legal weight if this is not part of the Standard and believe that key provisions are in this section. It seems it should be part of the Standard.
Ameren	Yes	This is helpful information to have that does not clutter up the requirements and measurements. Under R6, the third paragraph, there is a typo: ..."230kv transmission lines at least once 'line' during the calendar year".
City of Tallahassee (TAL)	Yes	This is very useful information and will minimize misinterpretations by the entities and the compliance teams.
Progress Energy Carolinas	Yes	This new section provides additional information and SDT rationale that is critical to understanding how to comply with the requirements in the standard and will also provide SDT intent/basis for the interpretation process when necessary. Progress Energy believes that any references to the Bulk Electric System in the standard sections and guidance/technical reference document should be reviewed and changed (e.g. “grid reliability”) to avoid confusion with the applicability section in this draft and avoid the potential for applicability interpretations once this version is adopted.
Independent Electricity System Operator	Yes	This section should be placed in an appendix preceded by a statement that clearly states the purpose of the Section and indicates that the Guideline and Technical Basis Section does not in any way add to the requirements of the standard. Also, this section appears to be a summary of the Technical Reference Document but we could find no reference to the Technical Reference within the standard. This reference should be cited for the benefit of anyone seeking further detail.

Organization	Yes or No	Question 8 Comment
Western Area Power Administration - Upper Great Plains Region	Yes	WAPA - UGPR agrees with the concept of placing the background technical information in a separate section. We were a bit concerned with the Guideline for R7 because it seems to mandate many more items than were called for in the actual requirement in the body of the standard. Our belief is that the Guideline section should not infer or list any more requirements than the actual requirement dictates.
Ad Hoc Group subteam formed to review draft standard	Yes	We agree with the additional material as an aide to entities to further understand the basis for the requirements. In this spirit the information should support compliant behavior and thus the reliability objectives of the standard.
Dominion	Yes	While we agree that these can be useful, we are concerned about the 'last minute' change (March 24th) to the technical reference document being used by those reviewing the materials for this project.
Southen Company	Yes	Would it be better to have an official white paper associated with the standard rather than having this information in the standard? A white paper can be changed without seeking industry comments and approval from NERC, while information in the standard must go through the entire approval process. As it is structured now, information-only updates to the Technical Basis Section would require the entire standards approval process to be completed.
American Electric Power (AEP)	Yes	Yes, although American Electric Power does question whether auditors will be able to avoid reading and applying such text.
KCPL	No	I like information that helps to "guide" and "provide guidance", however, we already having trouble with information from FAQ's, White Papers, and other guiding documents creeping into the requirements by auditing teams. The inclusion of "guiding information" in the text of the Standard itself may promote adding to requirements. Although helpful, I recommend removing this text from within the body of the Standard.

9. Do you prefer putting URL links to reference materials in the Guideline and Technical Basis Section, or do you prefer putting the additional technical/information materials in appendices, where needed, to supplement the Guideline and Technical Basis Sections? Please explain.

Summary Consideration: Out of the 52 comment forms received, 28 forms indicated a preference for use of URLs, 22 indicated a preference for appendices and 5 indicated no preference. These results indicate that either approach would be acceptable. The SCPS agreed to put the information in an appendix rather than in a URL because it is difficult to maintain the accuracy of URLs over time, and because keeping the information in the body of the standard is less work for end users as all information would be in one place.

Organization	Yes or No	Question 9 Comment
MRO's NERC Standards Review Subcommittee		If there is background information contained in a URL link pertaining to a particular Requirement, that link should be with the Requirement that it pertains to.
Ad Hoc Group subteam formed to review draft standard		Judicious and correct use of citations should allow the proper documentation of references without the hazard of expired URLs or expansion from using appendices.
Tennessee Valley Authority		No preference, either way will work.
Consumers Energy	Prefer appendices	
Exelon	Prefer appendices	
PPL Electric Utilities Corporation (NCR00884)	Prefer appendices	
South Carolina Electric and Gas	Prefer appendices	
TO/TOP	Prefer appendices	
Tucson Electric Power Co.	Prefer appendices	
Western Area Power Administrtaion	Prefer appendices	

Organization	Yes or No	Question 9 Comment
Xcel Energy	Prefer appendices	
GCPD	Prefer appendices	Actually we prefer that they are separate from the standard entirely. See question 8.
Cleco	Prefer appendices	An appendix ensures the information is available and original at the time the document it supports was prepared.
ERCOT ISO	Prefer appendices	An Appendix would probably be easier to use, but either type of reference would suffice. Regardless of which is used, it should include a footnote that the information is “For Information Purposes Only” and are not a part of the Standard’s Requirements. If the information causes confusion, then it should be eliminated completely. Also, what types of materials are contemplated to be “reference materials”?
Oncor Electric Delivery	Prefer appendices	Appendices would memorialize documents vs URL links to reference materials that may change over time. This Standard was crafted from “todays” point of view and background information. Reference material might change and the URL would point to material not validating the current form, logic, and background of the Standard.
Entergy Services	Prefer appendices	Appendices, or reference to a single site for all referenced material, would be the most helpful from the standpoint of keeping the information together and more readily available.
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Prefer appendices	BGE prefers that such materials be included in the appendices.
NERC Staff (12 staff members)	Prefer appendices	It is not clear what part of the standard is being balloted and what part is not. In addition, it is not clear what process will be used to modify the guideline/technical basis section of the standard. This needs to be determined before this standard can be balloted.
FRCC Manager of Operations	Prefer appendices	Links can get broken - official records (ie. standards) need to stand alone.
City of Tallahassee (TAL)	Prefer appendices	The fewer places I have to navigate to the better I like it. I find too many “broken” URLs. This will also make it easier when I download a “complete set” of standards from the NERC website.
Dominion	Prefer appendices	Unless a ‘failsafe’ process is developed to insure URL links are keep up-to-date, preference is to locate all referenced materials within the standard (same URL). However, there are a number of ways that

Organization	Yes or No	Question 9 Comment
		URL linkage could be done. One would be to locate all Guideline and Technical Basis documents on a webpage dedicated to such documents. This would allow URL linkage at a higher level than if there is URL linkage for each Guideline or Technical Basis document. This is probably the easiest to maintain. Another would be to link each Guideline or Technical Basis document referenced in a standard to the same URL as that standard. Maintaining URL linkage is probably medium. Yet another is to have the URL link to a webpage created specifically for that Guideline or Technical Basis document. This is likely to be the hardest (require most effort) to maintain.
CenterPoint Energy	Prefer appendices	URL links tend to change over time due to administrative requirements. Moving them to the appendix will avoid revisions to the Standard. See also answer to Q3 regarding the Guideline and Technical Basis Section.
Florida Municipal Power Agency (FMPA) and Some Members	Prefer appendices	URLs can break
Nebraska Public Power District	Prefer appendices	URLs change periodically.
North Carolina EMC	Prefer appendices	Will need to put something in place to make sure that the links get properly updated if they change.
Ameren	Prefer the inclusion of URL links	
Arizona Public Service Company	Prefer the inclusion of URL links	
Bonneville Power Administration	Prefer the inclusion of URL links	
Consolidated Edison Company of New York, Inc.	Prefer the inclusion of URL links	
Duke Energy	Prefer the inclusion of URL links	
Ga Transmission Corp	Prefer the inclusion	

Organization	Yes or No	Question 9 Comment
	of URL links	
IRC Standards Review Committee	Prefer the inclusion of URL links	
Manitoba Hydro	Prefer the inclusion of URL links	
Omaha Public Power District	Prefer the inclusion of URL links	
Pepco Holdings, Inc. - Affiliates	Prefer the inclusion of URL links	
Southern California Edison Company	Prefer the inclusion of URL links	
Utility Risk Management Corporation	Prefer the inclusion of URL links	
Progress Energy Carolinas	Prefer the inclusion of URL links	Additional reference documents provide additional information that may be needed to understand how to comply and the basis of requirements, but they should not be included as appendices. The use appendices could result in a SDT process/effort for minor revisions to the reference document.
American Transmission Company	Prefer the inclusion of URL links	Also see ATC's comment on "Guideline and Technical Basis Section" in Question #3 above.
Independent Electricity System Operator	Prefer the inclusion of URL links	In general the additional reference materials may make the document extremely voluminous so we prefer URL links.
Northeast Power Coordinating Council	Prefer the inclusion of URL links	Links are preferable to alleviate the concerns expressed in question 8 above, especially with respect to FERC approval.
JEA	Prefer the inclusion of URL links	No strong preference.

Organization	Yes or No	Question 9 Comment
Tampa Electric Company	Prefer the inclusion of URL links	None
Western Area Power Administration - Upper Great Plains Region	Prefer the inclusion of URL links	None
Orange and Rockland Utilities, Inc.	Prefer the inclusion of URL links	Prefer the inclusion of URL links
East Kentucky Power Cooperative, Inc.	Prefer the inclusion of URL links	Provides for clarity and readability.
Southen Company	Prefer the inclusion of URL links	See answer to number 8.
American Electric Power (AEP)	Prefer the inclusion of URL links	The use of URL links is probably most appropriate for an increasingly web-based reference repository.
SERC OC Standards Review Group	Prefer the inclusion of URL links	This format adds clarity and improves readability.
SERC Vegetation Management Sub-committee	Prefer the inclusion of URL links	This format adds clarity and improves readability.
ITC Holding	Prefer the inclusion of URL links	URL links provide immediate access, are less cumbersome, and usually provide additional research material when accessed.
FirstEnergy	Prefer the inclusion of URL links	We prefer URL links. Although, we are not clear what this question is asking regarding "additional technical/information materials". Is the team referring to "supplemental" reference documents such as the technical reference white paper that was recently posted for stakeholder review on March 24, 2010? If so, we agree that supplemental reference material be included through URL links, perhaps at the end of the "Guidelines and Technical Basis" section of the standard.
KCPL	Prefer appendices	Although a good idea generally, too many times URL links change name or something else that makes the imbedded link unusable or takes you to the wrong place. Having an appendix ensures the

Organization	Yes or No	Question 9 Comment
		information is available and original at the time the document it supports was prepared.

10. Do you agree with the addition of the Background Section to allow provision of background information, and to elaborate on the reliability-related drivers for the standard/change? Please explain.

Summary Consideration: Most of the comment forms (42 out of 54) indicate agreement with the addition of the Background Section.

Some commenters expressed similar concerns as those for Text Boxes and the Guideline and Technical Basis Section that the information should not be subject to FERC's review and approval, and that the Background may contain Requirement material that is enforceable. Other commenters suggested that this Section is not needed given the addition of the Guideline and Technical Basis Section.

The SCPS believes that the Background Section serves a different purpose than the Guideline and Technical Basis Section. The Background Section provides the background that led to the development of the standard, tying it to the reliability drivers and principles. In essence, the Background Section gives readers the reasons for and the events that led to the development of the standard. The Guideline and Technical Basis Section serves a very different purpose as it provides readers with the technical background, general guidelines, and general practices or technical merits that the responsible entities could take or consider to help them meet the reliability requirements. The Guideline and Technical Basis Section can also be used to provide some examples to illustrate the coverage or intent of the requirements.

On this basis, the SCPS believes it is in the interest of the majority of commenters to keep the Background Section. The SCPS will communicate to the standard drafting team that the Background Section must not contain requirement material, and should not include any technical information that should be provided in the Guideline and Technical Basis Section. The Background Section will remain at the front of the standard. As noted in response to other questions, a legal statement will be added to clarify which sections of the standard are mandatory and enforceable.

Organization	Yes or No	Question 10 Comment
ERCOT ISO	No	Again, it is preferable to include this type of information in an Appendix as long as it is made clear that this is additional information and is not a part of the Standard's Requirements. However, if there is a chance that the additional information included in the Appendix is going to cloud the Requirements spelled out in the Standard, then our preference is to eliminate the additional information completely.
SERC OC Standards Review Group	No	Inclusion of a background section in a document that will be approved wholly by FERC give undue credence and weight to statements which may be included that are not necessarily factual 100% of the time. For example, the first sentence of the last paragraph of the background section reads as follows: "Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating." Obviously, woody stems do not grow during the dormant season, yet the background asserts that it does. There are other areas in this sentence that are not completely factual and should not be in a reliability standard. We recommend that the text "grid reliability" be substituted for "Bulk Electric System" on page 6 of the draft.
Consumers Energy	No	Not necessary.

Organization	Yes or No	Question 10 Comment
Northeast Power Coordinating Council	No	NPCC participating members believe this is more informational and appropriate on the individual standard's NERC Website "Under Development" page, in an announcement, cover letter, or to be distributed with the standard drafts.
Nebraska Public Power District	No	Same as item 7.
CenterPoint Energy	No	See answer to Q3.
Florida Municipal Power Agency (FMPA) and Some Members	No	The background belongs in the Guidelines and not as part of the standard.
FRCC Manager of Operations	No	The background section should be re-named "Technical Basis". Trim content and leave only the first and last paragraphs. In addition, all 5 paragraphs of the section as written should be moved to the front of the Guidelines and Technical Basis document as a "Background" section of that separate document. NERC should limit its use of "background" information within the reliability standard itself.
TO/TOP	No	The background section should be re-named "Technical Basis". Trim content and leave only the first and last paragraphs. In addition, all 5 paragraphs of the section as written should be moved to the front of the Guidelines and Technical Basis document as a "Background" section. NERC should limit its use of "background" information in reliability standards.
Cleco	No	The inclusion of the text implies additional requirements. Keep quidance to a separate paper.
Exelon	No	This information should be in appendices or reference documents available on the NERC standards site.
Ameren	Yes	
Arizona Public Service Company	Yes	
Bonneville Power Administration	Yes	
Central Maine Power, Iberdrola USA	Yes	
City of Tallahassee (TAL)	Yes	

Organization	Yes or No	Question 10 Comment
Duke Energy	Yes	
East Kentucky Power Cooperative, Inc.	Yes	
Ga Transmission Corp	Yes	
JEA	Yes	
Manitoba Hydro	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
North Carolina EMC	Yes	
Omaha Public Power District	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	
Southen Company	Yes	
Tennessee Valley Authority	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	

Organization	Yes or No	Question 10 Comment
Western Area Power Administrtaion	Yes	
SERC Vegetation Management Sub-committee	Yes	Allows for a more informed interpretation of the standard.
American Electric Power (AEP)	Yes	American Electric Power agrees with this change.
American Transmission Company	Yes	ATC agrees that the Background Section is helpful; however, NERC should define its purpose and goal. What is currently written is more than necessary to be included in this standard.
Dominion	Yes	Dominion agrees but suggests it be moved towards end (suggest between Administrative and Guideline/Technical basis sections).
Ad Hoc Group subteam formed to review draft standard	Yes	Great help in showing intent and reliability goal of the standard.
Southern California Edison Company	Yes	Including a background section should prove useful for future editions. However, at some point such information could be made accessible through URL links.
ITC Holding	Yes	ITC agrees with the addition of Background Section
GCPD	Yes	May help in iterpretations and in explaining to stakeholders in our organizations.
Tampa Electric Company	Yes	None
Western Area Power Administration - Upper Great Plains Region	Yes	None
Progress Energy Carolinas	Yes	Progress Energy agrees and believes that the background section will allow relevant background information that provided direction/guidance for the SDT to be readily available after the standard revision is adopted.
Entergy Services	Yes	The Background Section is helpful, but the last sentence states....."Thus, this Standard's emphasis is on vegetation grow-ins.". This statement seems to conflict with the outage Category 2 "Fall In" classification,

Organization	Yes or No	Question 10 Comment
		even though it is a fall in from within the ROW.
Xcel Energy	Yes	The Background section should be moved to the back, in front of the Guideline and Technical Basis.
IRC Standards Review Committee	Yes	This background is important for insertion at the beginning of a SAR. But for a standard-posting, it is suggested that this section is redundant and better inserted after the requirement and measures with the other Administrative materials.
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	This makes sense to BGE.
NERC Staff (12 staff members)	Yes	This provides a context for the requirements and is very beneficial in understanding the intent of the standard.
Independent Electricity System Operator	Yes	This section expands on the purpose statement and will promote a uniform understanding of the fundamental drivers for the standard and its requirements, as well as its philosophy and scope.
Consolidated Edison Company of New York, Inc.	Yes	We agree but believe the Background Section should be situated before the Applicability Section in the revised Standard and redundant verbiage should be removed.
Orange and Rockland Utilities, Inc.	Yes	We agree but believe the Background Section should be situated before the Applicability Section in the revised Standard and redundant verbiage should be removed.
FirstEnergy	Yes	We agree that a Background section is beneficial. However, we believe it may be more appropriate to move this information to the Guidelines section as a lead-in. Also, we suggest a rewording of the first sentence of the first paragraph on Pg. 2 which states: "Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations". We agree that vegetation can contribute to outages, but it cannot be the sole cause of major outages. Major outages can be prevented if other measures required by other NERC standards are implemented when vegetation causes a line or other equipment to malfunction. We suggest a rewording of this statement as follows: "Interference between vegetation and transmission lines located on many types of land have contributed to significant outages and operational challenges."
KCPL	No	I like information that helps to “guide” and “provide guidance”, however, we already having trouble with information from FAQ’s, White Papers, and other guiding documents creeping into the requirements by auditing teams. The inclusion of “guiding information” in the text of the Standard itself may promote adding to

Organization	Yes or No	Question 10 Comment
		requirements. Although helpful, I recommend removing this text from within the body of the Standard.

11. **Do you agree with the addition of an Administrative Procedure Section to place administrative/procedural requirements that are contained in the existing standards but which do not meet the results-based or risk-based criteria? Please explain.**

Summary Consideration: Most comment forms (36 out of 52) indicated agreement with this addition.

Some commenters questioned whether or not these Administrative Procedures are mandatory and if so, why they are not placed in the Requirements and Measures Section or at least renamed "Administrative Requirements". They asked, if the administrative requirements are mandatory, are they subject to compliance audit and if so, would a monetary penalty be applied?

Some suggested that if the administrative procedures are not mandatory requirements, they should not be included in standards and proposed the alternative approach of collecting data/reports through the Rules or Procedure Section 1600.

The intent of creating the Administrative Procedure Section is to separate the procedural and administrative requirements from the results-based reliability requirements since not performing the former tasks does not adversely affect BES control or performance or expose the BES to reliability risks. The SCPS will provide further clarity to the intent of this Section, and consider the use of Rules of Procedure Section 1600 for data/report collection as an alternative.

Organization	Yes or No	Question 11 Comment
Consumers Energy	No	
Nebraska Public Power District	No	Administrative requirements should not be included in the Standard, they may be construed unintentionally as a requirement.
GCPD	No	Anything not directly associated with the compliance requirements or for help with interpretations should not be in the standard.
Northeast Power Coordinating Council	No	As stated earlier, NPCC participating members don't understand if this section holds sanctionable requirements, and if so under what authority. Administrative items are best left to the ROP or Compliance documents. A results based standard's primary focus should be on the requirements, and the goal or reliability objective. Taking administrative requirements out of the formal requirements section, adding them to another section, and still deeming them to be requirements is of no value to reducing the administrative burden on the industry. This makes the implementation of the standard more burdensome due to the fact that these additional "requirements" now reside in different places in the standard document. NPCC participating members suggest if these are truly valid requirements they need to be together with the other requirements. If they do not meet the results based criteria, and were included in this "Administrative Procedure" section strictly because of that, then they need to reside in another document. Their continued appearance in the document dilutes the integrity of the results based standard initiative.

Organization	Yes or No	Question 11 Comment
Exelon	No	Exelon is concerned this will raise questions concerning what criterion separates an administrative requirement from a results or risk based requirement. How are administrative requirements to be treated in the CMEP?
CenterPoint Energy	No	It is not clear if the Administrative Procedure is a mandatory activity. It would be helpful if the intent of this section was stated within the Standard.Also, this section in not parallel with the Rating and Rated Electrical Operating Conditions exception contained in R1 and R2. We recommend the following parallel wording for the first paragraph of this section:"The Transmission Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying certain Sustained Outages of the categories defined below, while operating within the Rating and Rated Electrical Operating Conditions, determined by the Transmission Owner to have been caused by vegetation that includes, as a minimum, the following:"Also, the categories listed in this section do not have parallel language to M1 and M2. We recommend that this section should adopt the wording in M1 and M2 for the Sustained Outages to be reported. Currently, Category 2 and Category 4 do not distinguish between an IROL and Major WECC Transfer Path. This may become a tracking problem since they have different Violation Risk Factors. If this is not important, then Category 1A and 1B can be combined.
Consolidated Edison Company of New York, Inc.	No	It is somewhat confusing to have sanctionable requirements located in other sections of the Standard outside of 'Requirements and Measures.' The section title 'Administrative Procedure' is somewhat misleading; if it was renamed 'Administrative Requirements' we feel it would be clearer to the industry.
Orange and Rockland Utilities, Inc.	No	It is somewhat confusing to have sanctionable requirements located in other sections of the Standard outside of 'Requirements and Measures.' The section title 'Administrative Procedure' is somewhat misleading; if it was renamed 'Administrative Requirements' we feel it would be clearer to the industry.
SERC OC Standards Review Group	No	Reporting Outages is not a part of Vegetation Mgmt. Therefore, this reporting belongs in an Administrative Section or possibly via a NERC 1600 request. In no circumstance should it be a Requirement of the standard. In the last paragraph this section appears to place a requirement on a regional reliability entity: "The Regional Entity will report the outage information provided by Transmission Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages." Was this really intended? What if the RE fails to make a report?
IRC Standards Review Committee	No	Some additional explanation is needed. If the requirement is to do inspections, and compliance is measured on that basis only then the Administrative Section is OK. If the entity is mandated to also meet the actions specified in the Administrative Section, then the change is not acceptable. This standard's example administrative section is introducing new requirements into the standard, and those requirements should be in the standard. In short, if there is a reliability requirement than that is what should be mandated.

Organization	Yes or No	Question 11 Comment
		The idea of mandating administrative items that are often designed to make auditing (not operations or planning) simpler should not be mandated.
FRCC Manager of Operations	No	The "Administrative" section needs to be streamlined - remove the first 2 paragraphs - quarterly reporting is no longer required and would be an administratively redundant process to the self-reporting of outages. Leave the outage categories to support consistent self-reports. Delete last paragraph - reporting by the Regional Entities to NERC is a delegated function that should be governed by the delegation agreements, rules of procedure or other internal ERO process, not within a reliability standard since REs and the EROs are not users, operators, etc of the BPS.
TO/TOP	No	The "Administrative" section needs to be streamlined - remove the first 2 paragraphs - quarterly reporting is no longer required and would be an administratively redundant process to the self-reporting of outages. Leave the outage categories to support consistent self-reports. Delete last paragraph - reporting by the Regional Entities to NERC is a delegated function that should be governed by the delgation agreements, rules of procedure or other internal ERO process, not a reliability standard.
Ad Hoc Group subteam formed to review draft standard	No	The administrative procedure section is appropriate under results-based requirements. However, we believe that reporting requirements established under other methods, such as the CMEP, may be confused by including it. It is unclear how non-conformance with administrative procedures would be handled. Perhaps administrative procedures would be better handled under ROP Section 1600 data requests or other Rules.
Cleco	No	The inclusion of the text implies additional requirements. Keep quidance to a separate paper.
Florida Municipal Power Agency (FMPA) and Some Members	No	The reporting requirements really boil down to a self-reporting or self-certification process since the only items to report would be violations to the standard. If such quarterly reporting is desired, it is really a self-certification process and should be governed by that process and not through a separate Administrative Procedure.FMPA recommends deleting the last paragraph - reporting by the Regional Entities to NERC is a delegated function that should be governed by the delegation agreements, rules of procedure or other internal ERO process, not within a reliability standard since REs and the EROs are not users, operators, etc of the BPS, and are not designated in the Applicability section.
Ameren	Yes	
Arizona Public Service Company	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 11 Comment
Central Maine Power, Iberdrola USA	Yes	
City of Tallahassee (TAL)	Yes	
Dominion	Yes	
Entergy Services	Yes	
Ga Transmission Corp	Yes	
Manitoba Hydro	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
NERC Staff (12 staff members)	Yes	
Omaha Public Power District	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	
Southen Company	Yes	
Southern California Edison Company	Yes	
Tennessee Valley Authority	Yes	

Organization	Yes or No	Question 11 Comment
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	
Xcel Energy	Yes	Are we to understand that the requirements listed in the Administrative section are not sanctionable from a NERC compliance perspective?
American Transmission Company	Yes	ATC feels this adds good will on the part of the entity to submit necessary reports, however, ATC requests clarification whether this section is subject to NERC violations. (Currently not listed in Table 1 Time Horizons, VRFs and VSLs)
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	BGE agrees with addition of an Administrative Procedure section.
Duke Energy	Yes	During the WEBINAR, a question was raised regarding how failure to meet an Administrative/Procedural requirement would be addressed by the Regional Entity. Can the Standard Drafting Team prepare a response to the question?
JEA	Yes	However, it needs to be made clear whether this is subject to audit, and whether failure to meet the requirement is subject to the same or different enforcement procedures as the numbered requirements in the standard.
East Kentucky Power Cooperative, Inc.	Yes	I do not believe that reporting of outages is a part of development and implementation of a Vegetation Management Plan. I fail to see how it brings value to the standard.
ITC Holding	Yes	ITC agrees that the “administrative role” such as outage reporting; shouldn’t be a reliability requirement and are more appropriately defined as an administrative procedure. We would also like some clarification on whether this section of the standard is subject to NERC violations. Currently it’s not listed in Table 1 Time Horizons, VRFs and VSLs
Western Area Power Administration - Upper Great Plains Region	Yes	None

Organization	Yes or No	Question 11 Comment
Tampa Electric Company	Yes	Not sure why separating 1.A & 1.B is preferred over 1,2,3,4?
Progress Energy Carolinas	Yes	Progress Energy agrees that "Administrative" functions such as outage reporting should not be listed as a reliability requirement and are more appropriately defined as an administrative procedure. (Outage reporting is an administrative function that does not directly improve reliability which should be the focus of reliability standard requirements.)NERC has other formal information request procedures in place (such as a NERC 1600 request), if that becomes necessary to ensure outage reporting.
SERC Vegetation Management Sub-committee	Yes	Reporting Outages is not a part of Vegetation Mgmt. Therefore, this reporting belongs in an Administrative Section or possibly via a NERC 1600 request. In no circumstance should it be a Requirement of the standard.
Western Area Power Administrtaion	Yes	The Administrative Procedure section could be moved forward following the Background section to better introduce the general administrative overview for what would then become the following Requirements, Measures, etc. These general administrative and procedural requirements are more easily overlooked when they included at the back of the Standard.
American Electric Power (AEP)	Yes	This addition is acceptable
Independent Electricity System Operator	Yes	This section imposes an additional reporting requirement but there is no associated VRF or VSL. Is this intentional? How will failure to report on time be treated? This is unclear as is the significance of any such Administrative "Requirements" within the standard, in general. Is the intention to establish separate procedures to govern the administrative and reporting obligations of registered entities under the Rules of Procedure?
FirstEnergy	Yes	We agree with the Administrative Procedure Section. Monetary fines should not be imposed for noncompliance with administrative requirements.
KCPL	No	It is too easy to unintentionally infer or introduce something that is not intended to be a requirement, but gets interpreted as a requirement in this section. Standards should be clear in what is a requirement and what is helpful information. If these are requirements, then propose them as requirements. If not, then remove to another guiding document.

12. Is there any other information that should be included in the standard document? If so, please explain why you feel that this information should be included.

Summary Consideration: None of the commenters offered any suggestions for including additional information that has not already been suggested in one or more of the comments provided in Questions 3 to 11.

Some commenters provided comments on the standard content itself.

Some commenters commented on the “Informal Comment” process. While this process may be useful in speeding up the process of developing standards, it introduces a potential for a given Team to ignore valuable comments (either because the issue is unknown to them, or because the proposal does not agree with the team’s ideas). They suggested that all comments (both formal and informal) be posted immediately for all to review. The SCPS agrees with the suggestion however the software currently used to collect stakeholder feedback doesn’t format the data collected in a manner that is easy to understand. NERC staff is exploring alternatives that would make it easier for stakeholders to view comments as they are submitted. The informal commenting process is meant to collect industry views in the same manner as the formal commenting process; it differs only in not requiring the SDTs to provide a response to each comment. Notwithstanding this provision, the SDT is still obligated to post all comments and provide summary responses to the comments.

Organization	Yes or No	Question 12 Comment
Ad Hoc Group subteam formed to review draft standard	No	
American Transmission Company	No	
Bonneville Power Administration	No	
City of Tallahassee (TAL)	No	
Cleco	No	
Consolidated Edison Company of New York, Inc.	No	
Consumers Energy	No	
Dominion	No	

Organization	Yes or No	Question 12 Comment
Duke Energy	No	
East Kentucky Power Cooperative, Inc.	No	
Exelon	No	
Florida Municipal Power Agency (FMPA) and Some Members	No	
Ga Transmission Corp	No	
Independent Electricity System Operator	No	
ITC Holding	No	
JEA	No	
Manitoba Hydro	No	
Nebraska Public Power District	No	
NERC Staff (12 staff members)	No	
Northeast Power Coordinating Council	No	
Oncor Electric Delivery	No	
Orange and Rockland Utilities, Inc.	No	
Pepco Holdings, Inc. - Affiliates	No	

Organization	Yes or No	Question 12 Comment
PPL Electric Utilities Corporation (NCR00884)	No	
South Carolina Electric and Gas	No	
Southern California Edison Company	No	
Tennessee Valley Authority	No	
Tucson Electric Power Co.	No	
Utility Risk Management Corporation	No	
Western Area Power Administrtaion	No	
Tampa Electric Company	No	All areas have been addressed and clarified as needed.
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	No	BGE feels no other information is necessary for inclusion.
American Electric Power (AEP)	No	None
Western Area Power Administration - Upper Great Plains Region	No	None
GCPD	No	Too much already.
Omaha Public Power District	Yes	
SERC OC Standards Review	Yes	As suggested in comment six, an improvement would be also listing the applicable table rows with each requirement which consolidates all pertinent info with the requirement. Also, adding the penalty matrix would

Organization	Yes or No	Question 12 Comment
Group		facilitate discussions with property owners/agencies resisting maintenance activates. This standard indicates a lack of recognition that vegetation outages are not necessarily reliability events. In the quest for improved reliability, spending the money necessary to achieve perfect compliance with R2, as stated, either will increase customer rates unnecessarily or cause the misallocation of maintenance funding away from maintenance activities that have a substantially higher impact on reliability.
SERC Vegetation Management Sub-committee	Yes	As suggested in comment six, an improvement would be also listing the applicable table rows with each requirement which consolidates all pertinent info with the requirement. Also, adding the penalty matrix would facilitate discussions with property owners/agencies resisting maintenance activates.
Arizona Public Service Company	Yes	Clearance 1 needs to be put back into this requirement as written. This is a vegetation management standard and there needs to be clear direction on how the system is going to be maintain at the time of maintenance. This ensures a clear direction to the utility the system has to be maintained. ANSI A-300 part 1 and 7 needs to be a requirement within the standard. Following this consensus agreement within the Professional Utility Vegetation Management sector outlines a process for providing a reliable transmission system. At a minimum ANSI A-300 part 1 and 7 should be incorporated into the Guideline and Technical Basis Section as a resource for compliance with this standard. Prudence would dictate that it be adopted into this draft as the foundation of any transmission vegetation management program as it is the accepted standard for professionals who are responsible for managing vegetation for electric utilities.Personnel qualifications need to be included in the standard and should include minimum measures such that there is consistency across the industry. This ensures that personnel are qualified and will have ongoing training and education in utility vegetation management. For example: The person who manages the field operation should have at least 5 years experience in vegetation management be an International Society of Arboriculture Certified Arborist and a Utility Specialist.
Ameren	Yes	In 4.3.1, suggest that "ice" be included in circumstances beyond the reasonable control of a TO in addition to the other "acts of God".
Entergy Services	Yes	More clarifying language throughout the document would be helpful.
Progress Energy Carolinas	Yes	None, other than the comment about potential improvements in question #6.
IRC Standards Review Committee	Yes	Regarding the new format, the idea of using “Informal Comment Periods” may be useful in speeding up the process of developing standards, but it also introduces a potential for a given Team to ignore valuable comments (either because the issue is unknown to them, or because the issue does not agree with their ideas). How will the Standards Committee or others ensure the quality of the process does not suffer in this way? What type of review process is contemplated to detect such behavior? Having the Formal

Organization	Yes or No	Question 12 Comment
		comments at the end of the process may prevent subject matter experts (SME) from seeing the comments and perspectives of other SMEs. The SRC suggests that all comments (both formal and informal) be posted immediately for all to review.
Xcel Energy	Yes	See comments to #1, #7 and #13 of this form
FirstEnergy	Yes	See our other comments.
Central Maine Power, Iberdrola USA	Yes	Table 2 expand footnote - State that table 2 is intended as a buiding block to develop clearance at time of vegetation management work. See TVMP for clearances.
CenterPoint Energy	Yes	The detailed rationale for the required one year inspection cycle in R6 should be included in the Technical Reference. The explanation provided in the Rationale that it “seems to be reasonable” and in the Technical Reference that it is “reasonable based on upon average growth rates across North America and common utility practice” are unfounded and arbitrary without a specific reference to a North American study. The Technical Reference should contain an example diagram of “the portion of the ROW where the corridor edge zones are designated by regulatory bodies for vegetation to exist” taken from the examples in the Definition of Terms Used in Standard section. It is unclear how this example should be interpreted for compliance should a Sustained Outage occur from vegetation growing within this zone. It is common for regulatory bodies to push utilities to plant trees or maintain trees within transmission rights of way to “hide the lines”, and it is unclear if this example is attempting to encourage such practice by regulatory bodies at the sacrifice of reliability.In general, the Technical Reference should contain more specific examples of violations of the Requirements and highlight specific exceptions related to vegetation related outages.The background and basis for adding the term “Active Transmission Line Right-of-Way” should be added to the Technical Reference.The background and basis for 4.2.4 that excludes the Standard from applying to fenced substations should be added to the Technical Reference.Just as the force majeure statement (4.3.1) was moved to the Applicability section of the Standard, the exception for applicability beyond the Rating and Rated Electrical Operating Conditions should be included in the Applicability section as well. Currently, it is only included in R1 and R2. It should be made clear if the other Requirements and Measurements must consider conditions beyond the Rating and Rated Electrical Operating Condition.Within the Requirements and Measures section there should be subheadings for each type of Requirement, performance-based, risk based, and competency-based. This classification is only indicated in the Technical Reference.
MRO's NERC Standards Review Subcommittee	Yes	The NSRS believes a section for definitions and abbreviated terms such as, Active ROW, MVCD, and WECC is needed. Also, See comment above in Question 9 on URL links.
Southen Company	Yes	We feel a definition of Category 3 outages (non reportable outages) should be included under the

Organization	Yes or No	Question 12 Comment
		administrative procedures. Although these outages are not reportable, this would provide a mechanism for classifying these outages so the utility can maintain evidence of its investigation and the rationale for not reporting them.
KCPL	No	

13. Do you have any other comment regarding the draft FAC-003-2 Transmission Vegetation Management standard that have not been addressed above? If yes, please provide a reference to the section, requirement, or subrequirement that you believe should be changed, added or deleted and the rationale for your proposal.

Summary Consideration:

1. **Reasonable control** - Some commenters expressed that the phrase "reasonable control" is difficult to enforce, while others wanted it moved to another section of the standard.
   The term "reasonable control" is prevalent in many force majeure clauses. It intends to limit the extent of compliance responsibility to those conditions that are within the sphere of the TO's ability. The SDT have determined that eliminating the word "reasonable" would not detract from the original intent and have made the change to the standard.
   The SDT does not have a preference for the location of the force majeure language. This is within the scope of the Standards Committee Process subcommittee to address.

2. **Differentiate between "human error" versus "human activity" –** Some commenters requested further explanation of these terms.
   The SDT intended for the term "human activity" to be used in the Background section of the standard and have removed "human error". The SDT intends the phrase human activity to describe those human actions that are outside the control of the Transmission Owner such as logging, vehicle contact with tree, removal or digging of vegetation, horticultural or agricultural or arboricultural activity. The SDT proposes the following new Force Majeure text:

   "This Standard does not apply to any occurrence, non-occurrence, or other set of circumstances that are beyond the control of a Transmission Owner subject to this reliability standard, including acts of God, flood, drought, earthquake, major storms, fire, hurricane, tornado, landslides, ice storms, vehicle contact with tree, human activity involving, removal of vegetation, installation of vegetation or digging around vegetation, animals severing trees, lightning, epidemic, strike, war, riot, civil disturbance, sabotage, vandalism, terrorism, wind shear, or fresh gales (or higher) that restricts or prevents performance to comply with this reliability standard's requirements. Nothing in this section should be construed to limit the Transmission Owner's right to exercise its full legal rights on the Active Transmission Line ROW."

3. **Competency-based requirement R3**: Some commenters expressed that R3 is deficient in detail.

   The SDT determined that the following parameters demonstrate competency:

   - Understands the dynamics of conductor movement over its operating range and design conditions, understands the inter-relationship between growth rates and inspection frequency and choice growth control method. And successfully implements the understanding as evidenced by lack of vegetation related outages.
   - Conducts inspections on a frequency that accounts for vegetation growth rates and local conditions.
   - Considers scheduling and permit lead times.
   - Designs work plans that levelizes work load.
   - Utilizes best industry practices such as ANSI A300.
   - Develops vegetation maintenance plans that account for vegetation growth rates and local conditions.
   - Incorporates a feedback mechanism in the program.

- Balancing ROW management with cost and science.
- Establishes wire security zones.
- Documents non-compatible species.
- Exercises full legal rights on the Active Transmission Line ROW to avoid outages.
- Knows the condition of its ROW.
- Gives clear direction to field personnel so that they know what to do to maintain the clearances.
- Addresses an interim corrective action plan.

The SDT proposes the following modification to R3:

*"**R3.** Each TO shall document the procedures, processes, or specifications it uses to prevent the encroachment of vegetation into the MVCD. Such documentation will incorporate the dynamics of a transmission line conductor's movement throughout its Rating and Rated Electrical Operating Conditions and the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the Transmission Owner's applicable lines."*

4. **Flexible annual work plan** – Some commenter indicated that the word "flexible" in requirement R7 is difficult to enforce without more detail.

The SDT modified the requirement as follows:

*"**R7.** Each Transmission Owner shall complete an annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made provided they do not put the transmission system at risk."*

5. **The SDT revised Section 4.2.2 –** The SDT did not agree to the removal of the reference to FAC-014 and have re-inserted it.

*"**4.2.2.** Overhead transmission lines operated below 200kV having been identified as an element of an Interconnection Reliability Operating Limit (IROL) designated in compliance with NERC Standard FAC-014."*

6. **Reporting –** Some commenters recommend keeping the outage reporting language in the technical requirements section.

The Standards Committee Process Subcommittee is the appropriate body to address this issue.

7. **Gallet distances** – Some commenters asked how can reliability be equal or better when Gallet distances are less than IEEE distances.

At the Gallet distance, the probability of Flashover is zero. The current in-force version of the FERC Transmission Vegetation Management Program Standard (FAC-003-1) uses the minimum air insulation distance (MAID) without tools formula provided in IEEE Std. 516-2003 to compute the required minimum vegetation clearance distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

The current in-force version of FAC-003-01 allowed the TO's to use either Table 5 or Table 7 to establish the absolute lowest value for these minimum clearance distances. Table 5 could be used if the TO knew the maximum transient over-voltage factor for its system. Otherwise, Table 7 would have to be used. Table 7 represented minimum air insulation distances under the worst possible case transient over-voltage factor. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

The SDT sought out a different method of establishing these absolute minimum clearance distances that considers both the outside weather environment and also the realistic maximum transient over-voltages factors for in service transmission lines.

In general, the worst case transient over-voltages occur on a transmission line when the line is open on one end and is opened on the other and then inadvertently re-energized when trapped charge is present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case scenarios mentioned above can be ignored.

For the purposes of FAC-003, the worst case transient over-voltage then becomes the maximum value that can occur with the line energized. Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service AC line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without a pre-insertion device (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. 362 kV), the maximum transient over-voltage of an “in-service” ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 242 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equation is a proven method of computing the required strike distances for proper transmission line insulation coordination. These equations were developed for both wet and dry applications and can be used with any value of transient over-voltage factor.

When one compares the Minimum Air Insulation Distances using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes using identical transient over-voltage factors it is clear that the Gallet equations yield a more conservative (larger) minimum distance value.

The following table is an example of this comparison:

Comparison of spark-over distances computed using Gallet wet equations

vs.

IEEE 516-2003 MAID distances
using realistic transient over-voltage factors

(AC) Nom System Voltage (kV)	(AC) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	IEEE 516 MAID (ft) @ Alt. 3000 feet
765	800	1.4	8.89	8.65
500	550	1.4	5.65	4.92
345	362	1.4	3.52	3.13
230	242	2.0	3.35	2.8
115	121	2.0	1.6	1.4

8. **Definition of Active Transmission Line ROW –** Some commenters indicated that the Active Transmission Line ROW definition is unclear.

   The SDT thoughtfully considered FERC staff's concern regarding the Active Transmission Line Right-of-Way. However, in light of the Commission direction in Order 693, in response to First Energy's concern about unnecessary expense of managing unused rights-of-way, to include such a provision, the SDT was left with only two practical choices, the current proposed definition or a fill-in-the-blank site-specific TO-designated approach. Acknowledging the desire to eliminate fill-in-the-blank requirements, the SDT opted for the proposed definition. Therefore, the SDT respectfully suggests that no workable change can be made to this definition and still implements Commission direction and thus has opted to retain the current draft language.

9. **R4: "Responsible control center" and "verified knowledge"** – Some commenters remarked that there is no "Local Control Center" entity in Functional Model and that could be an enforcement issue. Other commenters sought clarification for the phrase "verified knowledge".

   The SDT clarified R4, M4 and Rationale text box:

*"**R4.** Each Transmission Owner shall notify the responsible control center without undue delay when qualified personnel confirm the existence of a vegetation imminent threat. A vegetation imminent threat condition is one which is likely to cause a Fault at any moment."*

*"**M4.** Each Transmission Owner that has experienced a confirmed vegetation imminent threat will have evidence that it notified the responsible control center."*

*"**Rationale***

To ensure rapid notification of the correct personnel when an occurrence of a critical situation is observed. Qualified personnel may include line workers and utility arborists. The responsible control center is selected to ensure that the flow of operational information, which includes broken cross-arms and tree issues, will continue to the Transmission Operator (or its delegate)."

10. **R6 and R7** – Several commenters noted that R6 and R7 were assigned High VRFs although they previously were Medium.

SDT changed R6 and R7 from High to Medium. The justification is provided by NERC VRF Worksheet Tool and review of NERC VRF Guideline. (See attached VRF_Tool_R6.pdf and VRF_Tool_R7.pdf documents for the VM SDT consensus response utilizing the VRF Tool.)

11. **Requirements R1 and R2** – some commenters stated:

i. The MVCD requirements R1 and R2 need more detail to be enforceable and auditable. They do not see how FAC-003-2 addresses sag and sway with the elimination of Clearance 1.

ii. Concern that the VRF for lines covered in R2 is a Medium.

Consideration:

i. The SDT understands the commenter's concern. The SDT worked on addressing the concern by drafting alternate language to be responsive to issues of enforceability and auditability and offer the following as an alternative R1/R2 for industry comment:

*"**R1.** Each Transmission Owner shall manage the floor of its Active Transmission Line ROW in accordance to one of the following at all times:*

A) A fixed maximum vegetation height of 15 feet from the ground at the mid-half of the span and 20 feet in the outside quarters of the span, or,

B) A calculated maximum vegetation height that is the sum of the minimum conductor height at "max sag" plus MVCD plus cycle growth, or,

C) A calculated minimum vegetation to conductor clearance that is the sum of "max sag" in the span plus MVCD plus cycle growth, or, *D) A value determined by the Transmission Owner to provide a separation between the conductor and the vegetation that is comparable to options A, B, or C.*

E) Any alternative approach that ensures no encroachment occurs within MVCD, considering the sag and sway of the conductor throughout its operating range under rated conditions.

F) A value to provide a separation between the conductor and the vegetation that is the sum of MVCD, and a value that considers the sag and sway of the conductor throughout its operating range under rated conditions plus 10 feet."

NOTE: The SDT suggests similar language as found in the posted draft for measures M1/M2 may be appropriate with this alternate R1/R2.

ii. The SDT considered the comments that pertain to the assignment of a Medium VRF to R2 on the basis of IROL/Major WECC Transfer Path designation. The SDT determined that the assignment of Medium is justified because the loss of non-IROL or non-Major WECC Transfer Path lines pose a lower reliability risk than those lines that are elements of an IROL or Major WECC Transfer Path.

Organization	Yes or No	Question 13 Comment
American Electric Power (AEP)		American Electric Power suggests replacing the term "Minimum Vegetation Clearance Distance" with "Critical Vegetation Clearance Distance." The use of "minimum" suggests that the minimum is acceptable. However, in dealing with landowners or land managers, we may not be able to negotiate any more than the minimum. "Critical" would help convey the sense that the distance borders on dangerous unacceptability.
Central Maine Power, Iberdrola USA	No	
Consumers Energy	No	
East Kentucky Power Cooperative, Inc.	No	
IRC Standards Review Committee	No	
Manitoba Hydro	No	
Pepco Holdings, Inc. -	No	

Organization	Yes or No	Question 13 Comment
Affiliates		
PPL Electric Utilities Corporation (NCR00884)	No	
South Carolina Electric and Gas	No	
Southern California Edison Company	No	
Tennessee Valley Authority	No	
Tucson Electric Power Co.	No	
Tampa Electric Company	No	None
FRCC Manager of Operations	Yes	- Applicability Section 4.3 - use the term "Exemptions" instead of "Other" as it is more descriptive.- As noted earlier - Applicability Section 5 - use the term "Technical Basis" instead of "Background" and streamline by removing paragraphs 2, 3 and 4.- R
American Transmission Company	Yes	(a) R1 and R2 (pg.7) - What is meant by “to avoid a Sustained Outage”. Could be argued that a grow-in that does not cause a Sustained Outage is acceptable. (Could this be a FERC issue?)(b) R5 (pg.9) - ATC believes the term “temporarily” should be stricken from the requirement. This leaves too much to interpretation and does not add to the requirement(c) R6 (pg.9) - The descriptive timeframe “at least once per calendar year” is used. What does this mean? Every 365 days or a 12 month period within a calendar year? NERC needs to define this.(d) R4 (pg.15 in the Guideline and Technical Basis) - The term “verified knowledge” is used which does not seem consistent with the definition of “Verified Knowledge” in R4 Rationale on pg.8.(e) R4 (pg.16 in the Guideline and Technical Basis) - The term “responsible control center” is used and further defined. ATC believes this is the Transmission Operator. This should either be moved to the “Definitions of Terms” section or to R4 of the standard where the term is used.
Western Area Power Administrtaion	Yes	1) It is suggested that the word "located" in the third bullet in Measure 1 and Measure 2 be replaced with the word "originating". As worded, M1 or M2 could be interpreted to mean that vegetation originating outside of the right-of-way which blows or sways into contact with conductors “located inside the ... right-of-way” would be evidence of a violation of R1 or R2. Utilities generally are very limited in their ability to manage vegetative conditions outside of their right-of-

Organization	Yes or No	Question 13 Comment
		ways.2) Please reference the comments under Question 2 above regarding the incompleteness of requirements R3 and R7 in fully replacing the CCZ management concepts utilized in the Draft 1 version of the proposed FAC-003-2.3) The requirement R4 Guidelines and Technical Basis narrative is inconsistent with requirement R4. Specifically, in the Guidelines and Technical Basis section the second paragraph’s introductory sentence identifies a requirement for an imminent threat procedure, and the second bullet in this paragraph identifies a need to identify vegetation related conditions that warrant a response. Neither of these items are a requirement of R4 as currently written. R4 only speaks to the notification of the responsible control center when it has verified knowledge of a vegetation imminent threat condition.4) The requirement R7 Guidelines and Technical Basis section is written with an inappropriate bias towards very extensive or time based vegetation maintenance programs. Comments received from previous draft standard reviews have revealed that there are many other effective program approaches being utilized by the industry. It is suggested that this section be revised to broaden its scope to incorporate these other program approaches.
Ga Transmission Corp	Yes	1) I would like further examples of inactive portions of corridors. For example would a ten foot buffer strip that is in addition to a normal width to stay off a property line but is included in an easement plat but not cleared be considered inactive corridor or not? 2) The MVCD definition may not be realistic in its wording. Many utility companies may not be able to maintain these clearances at “design of Transmission Facility”. This needs further definition maybe “NESC moderate wind”. Many utilities in coastal areas will design lines for high sustained winds due to hurricanes these clearances may not be possible to maintain under these conditions however the line may be designed to with stand these winds.
FirstEnergy	Yes	1. Requirements R1 and R2 - We do not agree with the "zero tolerance" for real-time observation of encroachments that do not cause an outage. When discovered, most Transmission Owners (TO) take immediate action to alleviate encroachments and it is not appropriate to be fined for taking immediate action when no outage has occurred. Therefore, a violation should only occur when the TO has not immediately alleviated the situation within 24 hours. We suggest the following change to the first bullet in Measures M1 and M2: "Real-time observation of encroachment into the MVCD that is not corrected within 24 hours."2. Measurement M1 and M2 - For additional clarity, we suggest adding the following wording from Guideline and Technical Basis into M1 and M2 - "Brief encroachment by falling vegetation are not considered a violation."3. Requirement R4 - Since the intent of this requirement is the immediate notification of an imminent threat, we suggest adding the word "immediately" between "shall" and "notify".4. Requirement R5 - We suggest removing the term "temporarily" in the requirement. Some constraints faced by Transmission Owners are permanent and appropriate alternate action is permanently implemented. 5. Requirement R7 - Although we agree that the TO should be allowed to adjust the plan, the use of the term "flexible" is subjective. Additionally, the phrase "to ensure no vegetation encroachments occur within the MVCD" is redundant with the other requirements of the standard. Therefore, we suggest revising the wording of Requirement R7 to the following: "Each Transmission Owner shall implement an annual vegetation work plan. Adjustments to the work plan to defer work beyond the calendar year are acceptable and shall be documented."6. Coordination between Project 2007-07 and 2010-07 - Since the TO-GO interface team has identified the need for Generator Owner (GO) applicability in the FAC-003 standard, we believe that these two drafting teams should coordinate the addition of the GO into this Version 2 of

Organization	Yes or No	Question 13 Comment
		FAC-003. It would not seem sensible to revise Version 1 of FAC-003 to include the GO while Version 2 is developed and approved without applicability to the GO.7. Compliance Section - Under "Additional Compliance Information", we suggest removing the parenthetical phrase "See Administrative Procedure" and replace with "None". Since the Administrative Procedure is not part of the requirements, it is not sanctionable and should not be included in the Compliance Section.
MRO's NERC Standards Review Subcommittee	Yes	1. Need definition for the phrase “Major WECC Transfer Paths”.2. In question 2 of the comment form, it refers to the “bulk power system.” This standard does not cover the bulk power system, it covers lines above 200kV and certain ones below 200kV.
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	4.2.4 States that the Standard is not applicable to “...to Facilities .... located inside the fenced area of a switchyard, station or substation”. This implies that anything within the fenced area of a switchyard, substation or power plant does not fall within the jurisdiction of FAC-003-2. Some fenced in areas could be very large and susceptible to vegetation encroachments issues.4.3.1 Suggest including in the Force Majeure government a phrase referencing government interference, such as “Federal, State or other regulatory interference, including legal or other legislative actions, that prevents performance to comply with this reliability standard.”M1 & M2 bullet: “Real-time observation of encroachment into the MVCD” implies that real-time observation of vegetation encroachment ensures reliable operation the Bulk Electric System. The reliability standard objective states;”To improve the reliability of the electric Transmission system by preventing those vegetation related outages that could lead to Cascading.”However, real time observation of current operating conditions provides no assurance that vegetation will not lead to outages. BGE recommends removing the language. If an inspector finds vegetation encroaching into the MVCD during a visual inspection he / she should immediately initiate an Immediate Threat Notification. Therefore, this measure has no value.Disagree with R6. - Inspection Frequency. Very prescriptive. Please consider allowing TO’s to select an annual frequency that best fits their requirements, such as calendar year, every growing season, every non-growing season, etc. BGE currently defines their inspection frequency as annually during the non-growing season, October 1 to May 1. BGE believes inspecting during the dormant season is a best practice due to the ability of the inspector to identify vegetation defects, especially off the ROW, which could be hidden during the growing season due to foliage, canopy cover, etc. Also, if a utility elects to leverage an advance technology, such as LiDAR, it provides the most effective results when LiDAR is utilize during the growing season, therefore allowing the results of the advance technology to enhance the fall to spring inspection cycle. All of the above comments are submitted on behalf of: - Baltimore Gas & Electric Company - Constellation Energy Group, Inc. - Constellation Power Source Generation, Inc. - Constellation Energy Commodities Group, Inc. - Constellation New Energy, Inc. - Constellation Energy Nuclear Group, Inc.
Arizona Public Service Company	Yes	APS objects to number 3 Objectives statement. This is the only reliability standard that has at its Objective to prevent vegetation related outages that could lead to cascading. This is a reliability standard and its objective needs to be: “To improve the electric Transmission system by preventing vegetation related outages.” Requirement 6: To ensure reliability the TO’s are responsible for doing an annual inspection. You either do it or don’t and if you don’t finish it you should be held accountable. There shouldn’t be a lower VSL because you didn’t finish all of it. This is poor

Organization	Yes or No	Question 13 Comment
		planning on the utilities part.Requirement R7: When developing the annual work plan the Transmission Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Transmission Owners may also need to consider those special landowner requirements as documented in easement instruments. There needs to be parameters for the TO to show they allowed time for procedural requirements. An example, some land agencies will give you permission to perform work in as little time as two weeks and others can take two years. Even within the same land agency the timing of approvals is a moving target. APS recommends the TO must show documentation it submitted their Vegetation Management Plan to the land agency at least 120 days prior to the required start date. If the land agency doesn't respond within this time frame and the utility can not perform the work they shouldn't be held responsible.
JEA	Yes	Generally, I believe this document is a huge improvement. The requirements are much clearer and easier to implement than some versions from the past. I do not understand why R7 is still in this standard however. It appears to be a requirement whose purpose is only to dictate HOW an entity must document its implementation of its vegetation management program. Thus, I believe this requirement should be removed.
Consolidated Edison Company of New York, Inc.	Yes	In R5, the SDT should better define the phrase 'where a transmission line is put at potential risk due to the constraint.' This is rather vague and could lead to inconsistent practices between utilities. Con Edison defines all undesirable species on the full width of the ROW as 'potential risks to the transmission line' regardless of height or location at the time of vegetation management. Interim corrective action should only be required when the potential risk is approaching the imminent threat classification.
Orange and Rockland Utilities, Inc.	Yes	In R5, the SDT should better define the phrase 'where a transmission line is put at potential risk due to the constraint.' This is rather vague and could lead to inconsistent practices between utilities. ORU defines all undesirable species on the full width of the ROW as 'potential risks to the transmission line' regardless of height or location at the time of vegetation management. Interim corrective action should only be required when the potential risk is approaching the imminent threat classification.
Florida Municipal Power Agency (FMPA) and Some Members	Yes	In the Applicability section, the use of the term "Other" should be changed to another term, such as Force Majeure, since its purpose is not to include scope into the standard, but exclude scope from the standard.R4 uses the term "responsible control center", which seems inappropriate. Consider using the term "responsible operating entity". The M4 is simply a restatement of R4 without an example of types of evidence, e.g., such as voice recording, operator logs, etc.R5, consider using a different term than "constrained", which has other transmission related connotations. Possibly "limited" or "hindered".FMPA disagrees with a 3 year retention schedule for all of the Requirements and Measures. R4 and M4 would seem to be supported by operator logs, voice recordings and such and three year retention for such evidence is inconsistent with other standards.

Organization	Yes or No	Question 13 Comment
ITC Holding	Yes	In the previous draft the VRF's R6 and R7 were listed as Medium; and in the latest revision they are listed as High VRF's, what is the reason for this change or is this just a mistake?"Temporarily" should be removed from the requirement (R5 pg.9) this will be an interpretation issue and doesn't add to the requirement.
Northeast Power Coordinating Council	Yes	NPCC participating members recognize the hard work the drafting team has done and appreciate the efforts to address the issues presented. An issue seems to be a recurring theme with the advent of the MVCD. Some believe that the eventual adoption of this standard with MVCD will result in the reduction of current trimming cycles and clearance distances. Opinions have been expressed that this may result in increased vegetation contacts and trips. After reviewing some of the MVCD distances, for example 3.12 feet at sea level for 345kV, some expressed the opinion that this is much less than what typical trim practices are today, and may actually "lower" the bar for trimming practices, and effectively allow a TO to trim less and reduce the margin of clearance.Requirement R1 discusses encroachment. M1 bullet 1 states one way to violate encroachment would be:"Real-time observation of encroachment into the MVCD..."From a practical standpoint what is meant here? Who would determine this and how would it be done? The intent is certainly to avoid a sustained outage. However, if a TO was in the process of trimming after an active growing season, and noticed a slight encroachment while trimming, would it be considered a reportable violation? How would the RE measure compliance with avoiding something, with the absence of a sustained outage reported? A statement should be added to the "Definition of Terms Used in Standard" section to indicate how terms defined in the NERC Glossary and used in the standard are identified (for example capitalizing the first letters of the term or using italics or bold font). To avoid confusion when a term might be used at the beginning of a sentence, bolding or italicizing the term should be considered. The Guideline and Technical Basis section should be a separate document, and not part of the standard (mentioned previously in question 8). It should be included in the Technical Reference Document.Applicability 4.2.4--A fenced area of a switchyard, station or substation can have vegetation that could present a potential risk to facilities. What is the reason for this exclusion, and the exclusion in Applicability Section 5--Background paragraph 3 "...this Standard does not apply...to line sections inside an electric station boundary."Referring to our previous responses to questions 1 and 2 for Requirements R1, R2, and R3, what rating is used? It is possible to operate above a facility's normal rating for a prescribed time (for example a transmission line may be operated above its normal rating but below its LTE rating for up to 4 hours). Operating at emergency ratings should be considered. During emergencies transmission lines might be loaded to their emergency ratings, thus increasing the sag, thus increasing the likelihood of a vegetation caused trip if the required clearances don't take into account the increased loading. Especially in an emergency loading scenario, operating into an avoidable potential risk is very undesirable. Referring to FAC-003 - Table 2 - Minimum Vegetation Clearance Distances (MVCD), for 345kV (line to line), 3.12 foot (assuming to ground) clearance is required at sea level. IEEE Std 516-2003 IEEE Guide for Maintenance Methods on Energized Power Lines dated July 29, 2003, Table 5 (p. 20), lists the MAID (minimum air insulation distance) for 345kV phase to phase equipment at altitudes below 900 meters (2953 feet) to be 2.88 meters (9.45 feet) phase to ground. It is understood that MAID is "The shortest distance in air between an energized electrical apparatus and/or a line worker's body at different potential...", but the clearance differences at the various voltage levels seem very significant. If a figure is referenced in a requirement (R3), it would be preferable to have

Organization	Yes or No	Question 13 Comment
		that figure positioned within that requirement. If that is not possible, it should be explicitly stated where the figure can be found. Requirement R5--Legal actions and other events that prevent vegetation maintenance work be included in the Introduction Section 4.3.1. What does “interim corrective action” mean specifically? The requirement as written needs to be made clearer. Without the Rationale box it loses its meaning (refer to the question 3 response).Interim Corrective Actions are explained on page 28 of the separate Technical Reference Document, with examples such as modifying the inspection interval, or limiting the loading on the line (effectively changing its rating) to minimize sag. “Interim corrective action” should be defined and added to the Glossary.Are voltages referred to in the Standard (Applicability Section) line to line or line to ground for ac systems? (345kV line to line is 199kV line to ground, below the 200kV threshold in the standard). Are the voltages also applicable to DC equipment?
Xcel Energy	Yes	On page 6, in paragraph 5 ("Background"), we suggest enhancing the 3rd paragraph by inserting the words "Active Transmission Right-of-Way", as follows: "...addresses vegetation management in the Active Transmission Right-of-Way along applicable overhead lines..." This change emphasizes that this does not apply to areas outside of the Active Transmission Right-of-Way. Comments to Requirments and Measures Section (pages 7 -9)The term Minimum Vegetation Clearance Distance (MVCD) should be explicitly defined as a new "definition" rather than explained in a "rationale" box. Additionally, formalizing the definition would give weight to how "Table 2" is supposed to be used. As it is currently drafted, the requirements of the standard don't refer to Table 2 at all. (i.e., - our understanding is that the rationale boxes are for clarification and the requirements should be able to convey what is necessary on their own.)MVCD - while we understand this as an 'engineering term', the terminology is difficult to convey since land owners tend to question the need to do anything more than the "minimum". We recommend revising the term to "Critical Clearance Distance (CCD)". M1 & M2 should be revised to insert the concept of "verified knowledge" (that is used in R4). This is because M1 & M2 do not clarify whose real-time obseration it is referencing. As such, we recommend stating "Real time verified knowledge of encroachement into the MVCD..." instead of just the term "observation" to make it clear that a trained, knowledgeable individual is making this determination. Also, it may make sense to turn "verified knowledge" into a defined term since it will be used in M1, M2 and R4. If it is not made a defined term, then the meaning in M1 & M2 must be clarified in those sections (maybe a cross refefrence to as defined in R4 and on page 15 will work). However, we think it is best to make it a defined term.R5: Rationale box: consider enhancing the second sentence by adding the word "significant", to read "...avoid significant risk..."R5: Requirement & Measure: consider adding exception language when the constraint is known to be longer than "temporary". e.g. - stand offs can occur on right of ways that cross federal and tribal lands and the entity cannot force the federal government to do do something.R6: Xcel Energy still believes the requirement in R6 that mandates an annual inspection is too onerous and is at odds with the results-based approach of these revisions. Xcel Energy urges the retention of the provision in the existing standard that allows the Transmission Owner to set the frequency of inspection. In some areas of the country, annual inspections may not be adequate. Yet in other areas, a longer inspection frequency may be perfectly reasonable and practical. Our point is that inspection frequency should not be treated as if it were “one size fits all”. If treated this way, we feel this could pose a risk to reliability and is not likely to be cost-effective. The Transmission Owner should be allowed some flexibility. However, if the drafting team disagrees and determines that an annual inspection is to be mandated, Xcel Energy believes that an exception to the

Organization	Yes or No	Question 13 Comment
		annual inspection is appropriate when a non-subjective advanced technology such as LIDAR is utilized to achieve actual clearance distances. This places the Transmission Owner in a situation where it can rationally determine that the objectively measured distances result in a situation where an inspection need not be performed within the next year. It is suggested that R6 be revised to read as follows: Each Transmission Owner shall perform a Vegetation Inspection of all applicable transmission lines at least once per calendar year, unless the Transmission Owner, based on a non-subjective advanced technology, such as LIDAR, determines that a longer inspection period is appropriate.R7: Revise the requirement to eliminate the superfulous language at the end of the sentence that says "... to ensure no vegetation encoachments occur wihtin the MVCD", i.e., R7 would read as "Each Transmission Owner shall execute a flexible annual vegetation work plan."
Independent Electricity System Operator	Yes	Our comments to this point have focussed exclusively on the proof-of-concept for using the results-based criteria for developing a reliability standard. We have one comment on the specifics of Requirement R7 and its Measure M7. The rationale for M7 states that a flexible annual vegetation work plan allows for work to be deferred into the following calendar year provided it does not have the potential to become an imminent threat. This will evidently require some kind of assessment in each case. Will entities be expected to document those assessments as evidence in support of its view that the associated vegetation did not have the potential to become an imminent threat, or would it be sufficient to look at the outcomes of these decisions to defer items in the work plan - i.e. there were no imminent threats and sustained outages? Finally, we applaud the drafting team for its efforts in developing this draft. The industry has often commented about overly prescriptive requirements and I believe this draft has focused on the “what” of the requirements and left the “how” up to the appropriate entities. In our view this draft, with its succinctly stated requirements, represents an important first step in the right direction. Thank you.
Ameren	Yes	Page 9, M7 - what are the limits of flexibility in executing "a flexible annual vegetation work plan"?
Duke Energy	Yes	Please review the VRF Guideline because we believe that the VRF’s for R6 and R7 should possibly be changed to “Medium” instead of “High”. They were “Medium” in the last draft of FAC-003-2.
Westchester County Board of Legislators	Yes	Please see e-mail sent to sar@nerc.com. Thank you.
Progress Energy Carolinas	Yes	Progress Energy believes that the VRFs for R6 and R7 should be returned to “medium” since no singular “risk-based” requirement in a defense in depth strategy should be depended upon to eliminate/prevent risk to grid reliability. In a defense in depth strategy, no one specific “risk-based” or “competency” requirement should be “high” unless failure to complete that singular requirement will result in an immediate “high” risk to grid reliability (if that is the case, then the standard is not truly employing a defense in depth approach). Also, R6 and R7 (which have a zero tolerance) have no differentiation between grid impacting facilities (IROL) and facilities primary impacting local customer reliability (i.e., radial lines to load, etc).

Organization	Yes or No	Question 13 Comment
North Carolina EMC	Yes	R4: The requirement to notify the responsible control center of an imminent threat may potentially result in confusion at the control center if the transmission lines in question are not part of the control center's actively monitored grid. As an example, NCEMC has a few short radial 230kV lines that fall under the requirements of this standard, but these lines are not shown on the BA's control center system because they are downstream from a protective device located at a tap off networked transmission lines. A vegetation-related outage on these lines would not result in any of the transmission elements continuously monitored by the control center being outaged, and the operator receiving a call notifying the imminent threat may not have any familiarity with the line section being identified, since it is not on their system. If prompt action to respond to any imminent threat is the intended goal, why not consider making it a significant part of the mitigating factors of an actual outage.
City of Tallahassee (TAL)	Yes	Recommend deleting the “to avoid a Sustained Outage” in R1 and R2. Has a violation occurred if a momentary (successful reclose) outage occurs but the TO did not “observe(s) vegetation within the” MVCD? While it may not have to be reported on the quarterly report, Table 1 for the Lower VSL seems to suggest a violation of the MVCD has occurred, even if it was not “observed” as “required” in the Guideline and Technical Basis.In the Guideline and Technical Basis, the final paragraph for R1 and R2, line 3 contains an extra word “...encroachment is not be a violation...”In the Guideline and Technical Basis, the third paragraph for R6, line 2/3 contains an extra word “...230kV transmission at least once line during the calendar year.”
Cleco	Yes	Requirement 4:Recommend the SDT consider modifying to make it clear the requirement applies to threats within the right of way (ROW).Requirement 4.3.1:Recommend adding human activities to the list of causes. Logging activities are listed but other human activities such as private property owner tree care operations are not.
Exelon	Yes	See R6. Exelon prefers “annual” to “calendar” but notes the requirement runs counter to the results based approach and could be interpreted to be inconsistent with R7.The Rationale for R6 is ambiguous and without justification suggests shorter but not longer cycles are acceptable. If local factors can shorten a cycle, they could also increase it. The Rational is in conflict with the prescriptive nature of the requirement.
NERC Staff (12 staff members)	Yes	Standard Development TimelineThe Development Steps Completed section of the standard is incomplete. This section should include the dates of previous postings. Draft 1 of revised standard was posted for stakeholder comment from 10/27/08 - 11/25/08. Draft 2 of revised standard was posted for stakeholder comment from 09/10/09 - 10/24/09.Definitions of Terms Used in StandardThe definition of Active Transmission Right-of-Way is ambiguous and subject to interpretation. This definition need to be revised to add clarity. It is unclear what “active transmission facilities” are. In the gray box, the SDT should explain what “active portions of corridors” are, and how that is different than the “land that is occupied by active transmission facilities.” The terminology should be consistent. The example should state whether the width is the portion that has been cleared or should be cleared and if it was not maintained and should have been. The SDT should explain the reference to the National Electrical Safety Code in the gray box, and how it differs from the IEEE clearances. In addition, the team should explain why the Table 2 clearances set forth

Organization	Yes or No	Question 13 Comment
		in the standard itself are not referenced. The examples in the “inactive portion” suggest that there are active transmission facilities (see references to conductors and circuits). The SDT should provide the rationale for excluded them from vegetation management. While vegetation is permitted to exist at the corridor edge, the SDT should address why there is no obligation to maintain it. The revised definition of Vegetation Inspection does not seem necessary. It appears that the SDT is using the definition to set an expectation for enforcement by adding “which may be combined with a general line inspection.” If both vegetation and general line inspections are to occur concurrently, there should be minimum background requirements to perform such inspections. We recommend that the last portion of the draft definition be moved to the Application Guideline section so the definition of Vegetation Inspection should be “The systematic examination of vegetation conditions on an Active Transmission Line Right of Way.”The team should consider making Minimum Vegetation Clearance Distance a defined term.Effective DatesThe effective date for Ontario needs to be tied to the effective date in the U.S.With respect to the second exception, the team should provide the rationale behind the exception for the effective date for “existing transmission line operated at 200kV or higher that is newly acquired by an asset owner and was not previously subject to this standard”. All existing transmission lines operated at 200 kV or higher are currently subject to vegetation management. Please explain why a new owner would get an exception for this.Based on the wording in the Exceptions section, it appears that some lines in the US could be brought into this standard prior to regulatory approval. (i.e. Lines operated below 200kV, designated by the Planning Coordinator as an element of an IROL or as a Major WECC transfer path, become subject to this standard 12 months after the date the Planning Coordinator or WECC initially designates the lines as being subject to this standard. An existing transmission line operated at 200kV or higher that is newly acquired by an asset owner and was not previously subject to this standard, becomes subject to this standard 12 months after the acquisition date of the line(s))ObjectiveThe purpose of this standard should not be limited to outages that lead to Cascading, but prevention of all vegetation related outagesApplicabilityThis standard should apply to Generation Owners.The term Facilities is defined to exclude those in a fenced area of a switchyard, station or substation. The SDT should provide the basis for the exclusion.Footnote 1 needs to be clarified. It is too cursory.The “Other” section should not be included in this section. It is the expectation that the Compliance Enforcement Authority will not expect the Transmission Owner to prevent tree contacts that the TO could not prevent. This might be better suited in the Application Guideline section.In the “Other” section, the SDT should provide rationale for why the standard is not intended to address “human errors”.The SDT might consider rewording the “Other” section as:”This Standard shall not apply in circumstances where a requirement of this Standard was not complied with due to Acts of God, flood, drought, earthquake, major storms, fire, hurricane, tornado, landslides, logging activities, animals severing trees, lightning, epidemic, strike, war, riot, civil disturbance, sabotage, vandalism, terrorism, wind shear, or fresh gales that restricts or prevents performance to comply with this Reliability Standard's requirements, so long as the non-compliance was not caused by the fault or negligence of the Transmission Owner.”The team should provide justification for the applicability criteria they have selected; specifically why a 200 kV cutoff was chosen.The team should provide justification for eliminating fall-ins from outside the ROW.BackgroundAs a general comment, the background section seems repetitive.The fourth paragraph of the background section notes that this standard is not intended to prevent customer outages due to tree contact with lower voltage distribution systems. It is clear from the applicability section that this pertains to 200 kV and higher, although the standard contemplates that some lower voltage facilities could be subject to the standard. The SDT

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		should address whether this paragraph also address customer outages due to tree contacts with respect to 200 kV or higher facilities.Requirements R1 and R2:R1If an auditor were to assess compliance with R1, they would need to have the list of conductors that were associated with an IROL or a Transfer Path. This list should be identified in the list of evidence that must be retained.R1 & R2 In the Rationale box, the term “a proven transmission design method” is used. Please describe what this refers to, and whether these refer to the IEEE minimum clearances. The SDT should state what the method was and what changes, if any, were made to it.The SDT should address why the requirements only reference line conductors and not transmission facilities or transmission lines (the VSLs refer to transmission lines).The word “encroaching” should be replaced with another word/phrase that clearly defines the concept for compliance purposes. The word, “encroach” could be interpreted differently by different people (how close can vegetation grow before it enters the MVCD and is it a violation of R1/R2 - is it 2”, 2’, 10”, 10’?), whereas the word “enter” is explicit.Guidance is offered in the Guideline section of the standard that implies that all TOs should retain this evidence, yet the evidence is not identified anywhere in the Measures or evidence retention sections of the standard.We suggest adding the phrase, “of its” to clarify that the TO is only responsible for facilities it owns. “In addition, the Transmission Owner should maintain detailed records of the findings of its planned inspections. This documentation constitutes evidence that the Transmission Owner had no encroachments into the MVCD Table distances.”Immediately after the phrase MVCD, we suggest including the text “as specified in FAC-003-2 Transmission Vegetation Management Table 2 - Minimum Vegetation Clearance Distances (MVCD). Table 2 is not referenced in any of the requirements. If you require entities to use the MVCD as stated in Table 2, then this should be referenced in at least R1 and R2.M1 & M2Overall, it appears that these measures are asking for evidence of non-compliance. The initial item under M1 & M2 (shown below) should be rephrased with the addition of the words “verbal or written report of a,” otherwise the measure doesn’t seem as though it could be used objectively. In addition, the words Real-time should be removed, as they ad confusion to the issue.”Verbal or written report of a observation of encroachment into the MVCD, or”The phrase “Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period” should be changed to a footnote that reads “Consider Multiple Sustained Outages on an individual line, if caused by the same vegetation, as one outage regardless of the actual number of outages due to the same piece of vegetation”Momentary outages due to vegetation are also a violation of R1. Momentary outages from tree contacts may not result in a sustained outage but are evidence of a tree within the MVCD. The requirement should not be limited to only sustained outages. Consider this scenario: An entity self-reports a violation of the standard. Does that mean that if there is no actual "real-time observation" or a "Sustained Outage" there is no violation? Who must do the observing? Please explain.Requirement R3 Consider this scenario: A Sustained Outage occurs on a location that was not considered and therefore was not part of the TO’s TVMP. Would this result in a violation simply because the location was not considered when the entity developed a TVMP?Requirement R4 Each requirement should identify “who shall do what under what conditions, for what reliability outcome.” R4 has no identified reliability outcome. What is the reason for making a prompt notification? Is it to give the real-time system operator information on which to develop and implement an action plan if there is an outage on the line with the imminent threat? Then that should be stated in the requirement. R4 contains explanatory information. The sentence “A vegetation imminent threat condition is one which is likely to cause a Sustained Outage at any moment” should be moved to the blue box.Please explain what

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		“verified knowledge” means. The Rationale section does not really address this. While this is in the Guidelines and Technical Basis section, it defines it as “implies reliable confirmation.” This should be clarified and put in the measures section.”Imminent threat” should be defined so that it does not evolve into an enforcement issue.”Notify the responsible control center” should be clarified so that it does not evolve into an enforcement issue.Application Guideline for R4 should contain provisions in the imminent threat procedure for notification of the land owner.M4 should provide examples of acceptable evidence.Requirement R5 This requirement does not include a reliability outcome. The requirement should be rewritten to include a reliability outcome.Requirement R6 The Rationale for R6 is that one year “seems to be reasonable.” The SDT should address how this relates to the practice in place now, and whether it is consistent with current practice or is more or less than current practice. If inconsistent, the SDT should provide an explanation.The Rationale states the TOs should consider other factors that could warrant more frequent inspections. If so, the SDT should explain whether we are requiring them to do so if such factors exist.This requirement does not include a reliability outcome. The requirement should be rewritten to include a reliability outcome.Requirement R7 R7 is ambiguous; it is not clear how this could be enforced objectively. The rationale for the “flexible” plan indicates that the owner can delay work as long as it will not pose an “imminent threat.” The SDT should explain what the Compliance Enforcement Authority would look at to determine that the work that was delayed was not causing an “imminent threat.” The SDT should address whether it would ever be acceptable to delay work on a critical line (covered under R1).In Requirement R7, please explain what “execute a work plan” means. Did the SDT mean implement a work plan? As drafted, it could be read to just have one in place. The SDT should explain what “flexible” means. Does it mean there will never be a FAC-003 violation if you fail to implement the plan? The Rationale says the work can be deferred if it does not have the potential to become an imminent threat. Please explain. Corresponding clarification changes should be made to the VSLs for this requirement.Either M7 or the evidence retention for M7 needs to include the annual work plan. Without that the Compliance Enforcement Authority can’t determine if the plan was executed. The VSLs for R7 imply that the entire annual plan will be accomplished. . . not a “flexible” amount of the plan - the VSLs don’t line up with the use of the word “flexible.”According to the VSL Guidelines the VSLs should be stated in language that identifies the degree of noncompliance in language that identifies the amount that was noncompliant, rather than the amount that was compliant. VSLs for R6 and R7 are stated in terms of the % of the required performance that was compliant and should be rephrased. GuidelinesThe following guidance is offered in the Guideline section of the standard:Documentation or other evidence of the work performed typically consists of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, work inspection reports and walk-through reports.Documentation is required when the annual work plan is adjusted or not completely implemented as originally planned. The reasons for the deferrals or changes and the expected completion date of postponed work should be documented.This implies that all TOs should retain this evidence, yet the evidence is not identified in nearly this level of detain in the Measures section of the standard. In addition, no part of the requirement or measure is clear in indicating that documentation is required to support the need for a work plan adjustment. Evidence Retention The evidence retention periods specified don’t reflect the guidance in the SDT Guidelines. Should the evidence retention be the later of three years or three years from the last audit? The second paragraph should be stricken because it seems to contradict the first paragraph

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		retention period.VSLsThe SDT should verify that the VSLs for Requirement 3 are properly calibrated.Administrative ProcedureThe Administrative Procedure does not require prompt reporting of sustained outages; rather it requires only a quarterly report. This appears to be less stringent than the current requirements as employed today.The SDT should explain what “blowing together” means, and how this is different from a tree that grows into a line.FootnotesFootnote 1 should be deleted or modified. It is only relevant in explaining the proposed modifications to the standard. In footnote 4 the word, “substantially” adds ambiguity.Guideline and Technical BasisIn the Guidelines and Technical Basis section, it states “Requirements 1 and 2 state if the TO observes vegetation within the distances prescribed in FAC-003 - Table 2 it is in violation of this Standard.” This is actually in the Measures 1 and 2 and not the requirements.General commentsThere seems to be a lot of information not captured in the Requirements but rather are in various other sections. The SDT should clearly delineate whether these other sections are considered part of the Standard or just informational.With the next posting of the standard, the drafting team should include the following four points for stakeholder review:1. Justification for selection of the applicable lines. 2. Table listing each FERC directive and stakeholder issue (from the Issues Database) associated with the standard and identification of how the team addressed each of these3. Table listing each VRF and identification of how the proposed VRF meets both NERC criteria for setting VRFs and FERC’s five Guidelines for approving VRFs4. Document identifying how the proposed VSLs meet both NERC criteria for setting VSLs and FERC’s four Guidelines for approving VSLs.There is a significant concern with the use of the Gallet equations in this standard. This standard eliminates Clearances 1 and 2 from the previous version and replaces it with a single Minimum Vegetation Clearance Distance (MVCD) based on the Gallet equations. This approach reflects the most basic lowest common denominator and significantly lowers the bar versus the performance expected from the existing standard. Further, it would not appear that responsible entities would use the Gallet equations as the basis for the development of the vegetation management program. Additionally, whereas the multiple clearance zones provide an indicator of proactive vegetation management, the current proposal does not provide an equivalent demonstration of proactive performance. This approach appears inconsistent with Order 693 and the presentation of NERC standards to provide a defense in depth strategy, which is a fundamental outcome of the results-based standards process. Order 693 states in P24 that the “reliability mandate of Section 215 of the Federal Power Act....contemplates the prevention of incidents, acts, and events that would interfere with the reliable operation of the Bulk Power System.” The SDT should consider adding more clarification to the draft standard and white paper describing the building blocks for determining how much vegetation management (trimming) needs to be performed based upon growth rate of vegetation and the time between trimmings to reflect a proactive approach.The SDT should consider the impact of moving the reporting requirement in the existing standard to the compliance section of the new standard. The team should consider the reporting of this activity on an exception basis within a pre-defined timeframe following the event. This approach would provide more timely awareness to the Regional Entity and NERC of an event than the quarterly reporting expectation, and provide opportunities for identification and implementation of mitigating strategies in a more timely manner. While this approach removes an administrative type requirement from the standard that is believed to provide a deterrent to responsible entities, the increased timeliness of reporting in an exception basis would provide greater benefit to the effort to maintain reliability.Transmission Line is a defined term. The SDT should consider using this term in place of “transmission line.”The report identified in the administrative section of draft 3 of FAC-003 is really a “Periodic Data Submittal” used

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		to assess compliance and does not belong in an administrative section of the standard - it belongs in the compliance section of the standard. “Periodic Data Submittals” is one of eight different compliance monitoring and enforcement processes that may be used to monitor and assess compliance. The eight processes are identified in the Uniform Compliance Monitoring and Enforcement Program of the North American Electric Reliability Corporation and should not be mixed in with other processes or procedures. Each standard must list the appropriate processes in the compliance section of the standard so that there is a clear understanding of the purpose of the data submittal.As drafted, FAC-003-2 applies only to Transmission Owners. It also should apply to Generator Owners. The SDT should explain whether the issues brought forward in the GO/TO Report been considered and are addressed as part of this revision.Please update the mapping document so that it compares the last version of the approved standard to the latest proposed version of the standard so that it is easy to compare the proposed standard to the standard that is in force now.
Utility Risk Management Corporation	Yes	Suggested Improvements to M1. and M2.The purpose of Requirements R1 and R2 is to require the prevention of vegetation encroachments within the MVCD. As made clear in the background and remaining FAC 003-2 requirements, the overarching intent of FAC 003-2 is to prevent sustained outages caused by vegetation that could lead to cascading. However, both M1 and M2 include real-time observations of encroachment into the MVCD as an automatic violation of R1 or R2, respectively (even though the violations may not result in penalty or fine). This is inconsistent with the “defense in depth” goal sought by the committee, as a real time observation using new technologies may in fact demonstrate that the Transmission Owner is in fact aggressively managing vegetation to meet the MVDC requirements and is discovering new encroachments and remediating them quickly and effectively and thereby is not in violation of the standard.Similar to imminent threats, remediation procedures should be permitted for encroachments as well and serve to make clear the observation is not automatically a violation. Classifying a real-time observation of an encroachment automatically as a violation of R1 or R2 penalizes a Transmission Owner for identifying vegetation threats, which are less severe than imminent threats. Under Requirement R4, the transmission owner is permitted to take appropriate actions to alleviate an imminent threat through short term corrective actions upon observation of any vegetation that is near to or is encroaching into the MVCD. (See FAC-003-2 Guideline and Technical Basis, Requirement R4). Considering the allowance for remedial action under Requirement R4 when facing a condition that is “likely to cause a Sustained Outage at any moment,” it seems excessive to qualify a real-time observation of an encroachment as a violation of R1 or R2. We suggest a better approach is to modify M1 and M2 to allow for remedial action. Or, in the alternative, the standard should clarify that observations of encroachments using software-enabled technology, such as LIDAR coupled with work order management systems, do not constitute a “real time observation of an encroachment.” First, by modifying M1 and M2 to allow for remedial action as suggested below will deal with the concern we raise:M1. Evidence of violation of Requirement R1 is limited to: o Real-time observation of encroachment into the MVCD which is not mediated in accordance with R4. o ... M2. Evidence of violation of Requirement R1 is limited to: o Real-time observation of encroachment into the MVCD which is not mediated in accordance with R4. o ... In the Alternative, “Real-Time Observation” Should be Clarified. As noted above, a real-time observation of an encroachment is evidence of a violation of Requirements R1 and R2. Observations in real time mean “an actual field observation or measurement of the conductor-to-vegetation distance and not a calculated

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		determination of relevant positions." (See FAC-003-2 Guidelines and Technical Basis, Requirements R1 and R2) Given the current definition, it is not clear observations using software-enabled LiDAR would trigger violations and thereby would discourage the Standard's emphasis on preventing sustained outages or Cascading due to grow-ins. This may result in penalties for registered entities that are engaged in good faith activities to prevent sustained outages. The meaning of "real-time observation" should be clarified as to remove any adverse incentives for vegetation inspection and management. To implement this suggestion as an alternative to allowing remediation to prevent an observation from being an automatic violation, the definition could be reworded to state:"Real-time observation" means an actual field observation or measurement of the conductor-to-vegetation distance which is not performed under the regular Vegetation Inspection of Requirement R6 or annual vegetation work plans in accordance with Requirement R7. Such observations do not include calculated determinations of relative vegetation positions. Conclusion:Adopting one or both of these proposed changes would help R1 and R2 measures more fully meet the goal of preventing overgrown vegetation and systemic failures triggered by flash over, as stated in the background section on page 6 of FAC-003-2. The current M1 and M2 use of real-time observations conflicts with the expectation that utilities engage in "defense in depth" measures. As the guidelines conclude regarding Requirements R1 and R2, the Transmission Owner is expected to have a cohesive vegetation management program for managing vegetation in such a manner as to maintain separation between conductors and vegetation. This is to function in conjunction with the imminent threat procedure to facilitate interim corrective action. "However, brief encroachments by falling vegetation are not considered to be a violation." Making the changes suggested above - coupled with the existing requirement that the utility mitigate an observation in accordance with the utility TVMP through a response schedule - thereby advance the goals of the standard and take away an impediment to aggressive defense in depth.
SERC OC Standards Review Group	Yes	The requirements (R6 and R7) for inspections and the performance of work plans are part of a defense-in-depth approach and as such the TO is not depending on singular requirements to prevent sustained outages, therefore, the VRF for R6 and R7 should remain medium not high. We applaud the attempt to improve the readability and ultimate comprehension of reliability standards by changing to this new template. We have included some comments also made by the SERC Vegetation Management Subcommittee (VMS)."The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers."
SERC Vegetation Management Sub-committee	Yes	The requirements (R6 and R7) for inspections and the performance of work plans are part of a defense-in-depth approach and as such the TO is not depending on singular requirements to prevent sustained outages, therefore, the VRF for R6 and R7 should remain medium not high.
GCPD	Yes	The standard should include only R1, R2 and the Clearance Table. Everything else should be in guidelines as to how you might comply with the standard. If R3 thru R7 remain in the standard then it is virtually the same as it exists today, just put in a different order.

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CenterPoint Energy	Yes	The term "Active Transmission Line Right-of-way" (ATLROW) is not defined in sufficient detail in the Definition of Terms Used in the Standard section to know how to apply it to the Requirements and Measures. The Technical Reference merely depicts the relative position of energized conductors, but it does not show a graphical determination of the limits of the ATLROW. The ATLROW is missing a definable and determinable width in its current definition within the Standard which makes it an arbitrary term and does not allow for a clear and measurable expected outcome of each requirement. In several sections, the Standard relies on the specific determination of the physical width of the ATLROW to determine applicability of the requirements. The Vegetation Inspection definition refers to “on” an ATLROW. The Background section refers to “outside” the ATLROW. Table 1 refers to “within” and “on” the ATLROW. M1 and M2 refer to “inside” the ATLROW. R3 and M3 refer to “on” the ATLROW. The Administrative Procedure refers to “inside and/or outside” and “within” the ATLROW. The Guideline and Technical Basis section refers to “on or near” the ATLROW and the “limited” ATLROW “width”. It also says that, “The Transmission Owner should, therefore, endeavor to maintain its ATLROW to the full extent of its legal rights at all times in all cases.” Since the Standard does not currently define how a Transmission Owner is to determine the specific boundaries of the ATLROW, it would appear that the Transmission Owner is to make that determination on a case by case basis at its discretion. Should that not be the intent, we recommend the definition for the ATLROW to be, “A strip or corridor of land or aerial space that is occupied by energized transmission conductors with its operational clearance limits defined by the Transmission Owner’s specific legal rights but in no case less confining than the MVCD applied to the movement of the conductors within their Rating and Rated Electrical Operating Conditions.” This definition contains sufficient detail to determine the physical limits of the ATLROW, and it allows for vegetation management to apply within the full extent of the legal rights of the Transmission Owner while requiring a minimum area for vegetation management in undefined ROW’s to ensure Sustained Outages are minimized.M1 contains a reference to “real-time observation of encroachment into the MVCD” but does not explain who is to make the observation and where it is to be documented. If this is to be done by the Transmission Owner, then perhaps it should be a Measurement under R6 and recorded under M6.The language in R6 refers to inspecting “transmission lines” and Table 1 for R6 refers to inspecting “ROW”. Both areas should use consistent terminology.M1 and M2 have the potential for double jeopardy when a Sustained Outage occurs because the Violation Severity Level has an entry for an MVCD encroachment (which causes the outage) and another sister entry for the type of Sustained Outage. Some additional clarity in the application of M1 and M2 is necessary.R5 should include the exception stated in the Rationale text box to add clarity to the Requirement. R5 should read, “Each Transmission Owner shall take interim corrective action when it is temporarily constrained from performing planned vegetation work, where a transmission line is put at potential risk due to a constraint, except where the risk is avoided by implementing an alternate work methodology.” In the Guideline and Technical Basis section for R1 and R2 (page 15), there is a reference to records of “planned inspections” and “evidence” for no encroachment into the MVCD. This reference should be moved to R6 where the inspections are required. If R6 is intended to provide evidence for M1, then that should be stated in R6.In the Guideline and Technical Basis section for R6, the reference to the VSL calculation units and the example units should be consistent-the example should use “line miles”, not just “miles”.Table 2 contains several “*” in the voltage column that are not defined.In the Technical Reference on page 21, the following sentence should be deleted, “If constraints cannot be

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		overcome and if design clearances are sufficient, an exception to the Transmission Owner's 10-foot guideline might be made." The Technical Reference should not provide examples of granting exceptions as they may be misinterpreted as an endorsement by NERC to increase the planting of trees near and under transmission lines without taking into account several other factors such as ROW access, changing design conditions, future line additions and rebuilds. The inclusion of modifications to the wire zone on page 24 regarding the wire-border zone model should be re-examined to be sure they are specific to an environmental conservancy requirement while allowing for construction and inspection access as needed.In the Technical Reference on page 22 under Planning and Implementation, delete the sentence, "While designed primarily with transmission systems in mind, t is also applicable to distribution projects." The Standard should not imply its applicability to distribution systems since it is intended only as a transmission standard.In the Technical Reference, the last sentence on page 26 starting with "Appropriate actions..." should be moved to R5 where it applies. In general, the proposed FAC-003-2 has gone FAR beyond what was contemplated by the Commission in FERC Order 693 and equates to a total re-writing of the Standard for no apparent reason. The Commission's determination dealt with the following areas: (1) applicability; (2) inspection cycles; and (3) minimum clearances on National Forest Service lands. For instance in Paragraph 729, the Commission states, "As proposed in the NOPR, the Commission approves Reliability Standard FAC-003-1 with no proposed modification on the issue of clearances. The Commission reaffirms its interpretation that FAC-003-1 requires sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions...." Rewriting the minimum clearances introduced a new set of confusing definitions, and further burdens the Transmission Owners with new documentation requirements with little if any benefit when compared to the Clearance 2 concept in the existing Standard.A preferred approach would have been to incorporate the following few items into the existing Standard: (1) the RC versus the RRO; (2) the designation of a specific inspection frequency; (3) the Gallet equation; and (4) the applicability to National Forest Service lands.
Ad Hoc Group subteam formed to review draft standard	Yes	The wording in R7 is troublesome. We believe that the process for developing the annual work plan is imbedded in R3. As discussed in question 2, demonstrating capability to actually perform those actions necessary to ensure no vegetation encroachments occur within the MVCD is the primary concern. Deferring such work into the next calendar year appears contrary to this concern and neutralizes the defense-in-depth concept by diminishing the imminent threat requirement of R4 to a primary means of defense. While we don't want to incent vague annual work-plans, we also don't want to remove the imperative that the work must be done.
Nebraska Public Power District	Yes	Under section 4.3.1 add in ice storms as one of the force majeure events. This type of event may impact many TOs and should be included.
Oncor Electric Delivery	Yes	Use of the Gallet equation to determine the minimum gap between vegetation and conductor to prevent sparkover seems to be appropriate. No utility should be managing to this distance but developing a distance beyond this would be arbitrary. This is a reliability standard not a worker safety or vegetation management practices standard. As Federal agencies and other entities are interpreting the Standard to limit normal vegetation management efforts, the FERC should develop and adopt an overarching memo allowing utilities to maintain vegetation under any agency

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		jurisdiction as a utility manages vegetation along the entire right-of-way corridor.
Western Area Power Administration - Upper Great Plains Region	Yes	WAPA - UGPR would like to see "ice storms" specifically mentioned in Section 4.3.1. Having additional clarification as to what is considered a "major storm" would also be helpful.
Bonneville Power Administration	Yes	We believe the minimum vegetation distances are very granular and nearly un-measurable in real life. When a person considers the table to be a list of minimums it seems that the regulated entities, or land owners would want the distances to be as close to the wire as possible. We would not want a non-technical manager to believe that any small distance outside of the noted distances is ok.
Omaha Public Power District	Yes	We have concern over establishing proof an outage is exempt due to fresh gale. A fresh gale, or even a localized thunderstorm, can easily produce wind gusts that exceed the lines rated capacity for blow out. If an outage occurs under these conditions, the standard provides an exemption under Section 4.3.1, but there is often no way to empirically prove conditions exceeded the lines normal operating conditions. How should a utility handle these situations?
Southen Company	Yes	We have concern over establishing proof an outage is exempt due to fresh gale. A fresh gale, or even a localized thunderstorm, can easily produce wind gusts that exceed the lines rated capacity for blow out. If an outage occurs under these conditions, the standard provides an exemption under Section 4.3.1, but there is often no way to empirically prove conditions exceeded the lines normal operating conditions. How should a utility handle these situations? Please note there is a typographical error in the third paragraph on page 15, "...encroachment violation is not be a violation..."We would like to thank the Standard Drafting Team for their hard work. The time and effort they have put into developing this standard is obvious.
Dominion	Yes	While not related solely to this standard, we suggest that no future standard be effective until approval has been granted by the applicable regulatory authority. Having an effective date that differs from the mandatory date is causing confusion/chaos on the part of the applicable registered entity(ies). With the current process, it is possible to have a standard that is mandatory conflict with a superseding newer version (or a new standard that contains requirements meant to supersede those in the mandatory standard). Applicable entity(ies) may not be able to comply with both when this is true, and may not be able to take steps necessary to transition from mandatory requirement to superseding requirement without becoming non-compliant.
Westchester County Board of Legislators		1. <u>Bulk Electricity System NOPR</u> – FERC recently issued a notice of proposed rulemaking to revise the definition of "bulk electric system" (BES) to include all transmission facilities with a rating of 100 kV or above. 130 FERC ¶ 61,204 (Mar. 18, 2010). If approved, such revision might significantly increase the amount of transmission facilities subject to standard FAC-003. In areas with dense residential and commercial development, this revision will exacerbate

Organization	Yes or No	Question 13 Comment
		existing conflicts between homeowners, municipalities, affected transmission owners (TOs), and regulating agencies. As described in comments below, compliance with the existing or perceived requirements in FAC-003 has produced numerous conflict in areas of dense development and narrow rights-of-way between homeowners, TOs, and regulating agencies because of economic, environmental, and aesthetic impacts. If FERC adopts the proposed BES definition, then the FAC-003 standard (current 001 and draft 002) should be extensively reviewed by the drafting team to evaluate the amount of affected facilities and the need for standard revision to avoid as far as possible further conflicts. 2. "Background" Section 5 – The draft adds a new section titled "Background" (Section 5). The existing standard FAC-003-1 does not include a similar section. This narrative section appears to provide interpretation on the rationale for a vegetation management reliability standard and to clarify the standard applicability. This discussion may be more appropriate in the accompanying technical reference, which describes and clarifies standard FAC-003. While identifying overgrown vegetation as cause of major outages and operational problems, this section fails to state that many other causes can lead to Cascading events. Indeed, of the many NERC reliability standards, only one, FAC-003, concerns vegetation management. While the August 2003 blackout was initiated by a tree contact, there were numerous other factors that caused this power outage to spread to over a dozen states. Section 5 should therefore be revised to clarify that FAC-003 is only one of many factors that can lead to a large-scale grid failure. 3. Standard Applicability Across Land Uses – Standard FAC-003-1 and the proposed draft do not vary in applicability, even though the types of land uses within and adjacent to transmission facilities vary widely. Among certain land uses, such as dense residential development, this can lead to substantial conflict between the TO and adjacent landowners, especially concerning environmental, aesthetic, and economic impacts. The Westchester County Board of Legislators identified such problems in its recent resolution, available at http://meetings.westchesterlegislators.com/Citizens/FileOpen.aspx?Type=4&ID=2828&AgencyName=WestchesterCounty . Notwithstanding the reliability imperative expressed by Congress in enacting Section 1211 of the 2005 Energy Policy Act, the implementation of reliability standard FAC-003 has produced significant challenges for all parties in suburban areas. In particular, surburban area homeowners, often on small parcels, that abut or are near to transmission rights-of-way have experienced dramatic impacts upon their properties and property values when TOs exercise their "full extent of legal rights at all times and in all cases", as stated on page 18 of the draft. Therefore, the development of standard FAC-003 must consider this backdrop and select requirements and accompanying text that provide some balancing of electric reliabilty with environmental and economic impacts. As presently written, the draft does not acknowledge such balance. 4. Varying Conditions – Requirement R1.2.1 of Standard FAC-003-1 identifies numerous local conditions that should be considered in determining appropriate clearance distances. This balanced evaluation of factors should be retained in FAC-003-2. 5. Full Legal Rights – The draft encourages TOs to exercise full legal rights at all times and in all cases. This language

Organization	Yes or No	Question 13 Comment
		is not included in present standard FAC-003-1. As noted above, electric reliabilty and TO compliance with FAC-003 must not preclude other important societal factors. The language encouraging full exercise of legal rights should be removed from the draft.
KCPL	Yes	**<u>Requirement 4:</u>** Recommend the SDT consider modifying R4 to make it clear the requirement applies to that which is within the Right Of Way (ROW) for the transmission facility. Obviously, the Transmission Owner has no authority or control beyond the ROW. This is also an audit concern regarding "triggering" this requirement on a subjective evaluation of "imminent threat". How does a Registered Entity, Regional Entity or Auditor determine what constitutes an "imminent threat"? This will be a matter of opinion and makes this a difficult requirement regarding compliance when a difference of opinion arises. In addition, as proposed, this requirement does not address the need to take immediate corrective actions to mitigate an imminent threat. The previous FAC-003 Standard included taking action to remove the "imminent threat" which is not included in this proposed version 2. What was the intention of the SDT in this regard? Recommend the SDT consider language to include taking action to remove the imminent threat. **<u>In the "Guideline and Technical Basis" section:</u>** 1. Under R6: believe the word "per" is missing in the first sentence of the third paragraph between "once (per) line". 2. Under R7: concerned regarding the use of words such as "never", "at all times", and "in all cases" in the bulleted items with paragraph 6 in this section as a guiding document. This is the kind of material that is creeping into compliance audits and recommend softening this language. **<u>Violation Severity Levels</u>** 1. Do not agree with the zero tolerance for encroachments that do not result in a service interruption for R1 and R2. 2. Not notifying the Control Center should be a HIGH and not removing the imminent threat should be a SEVERE.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on 4th Draft of FAC-003-2 Transmission Vegetation Management —Project 2007-07 Vegetation Management

The Vegetation Management Standard Drafting Team thanks all commenters who submitted comments on the 4th draft of reliability standard FAC-003-2 — Transmission Vegetation Management. This standard and its associated implementation plan and technical reference paper were posted for a 30-day public comment period from June 17, 2010 through July 17, 2010. The stakeholders were asked to provide feedback on the standard through a special Electronic Comment Form. There were 45 sets of comments, including comments from more than 100 different people from over 50 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

The standard and its associated implementation plan and technical reference paper were balloted from July 9 – 19, 2010. The voting had a quorum of 86.18 percent and an affirmative vote of 65.93 percent. Because at least one negative ballot included a comment and the affirmative votes did not meet the two thirds threshold for approval, the results were not final.

On November 4, 2010, NERC staff provided a Quality Review of FAC-003-2 to the Standards Committee (SC). The SC met on November 11, 2010 to determine if the draft standard should proceed to posting. During the meeting, the SC requested the Vegetation Management Standard Development Team (VMSDT) to work with NERC staff in addressing the items identified in the Quality Review. The VMSDT conducted several conference calls and acted in good faith to produce Draft 5 of FAC-003-2. The VMSDT considered the feedback provided in the Quality Review by NERC staff and reached consensus in the following areas:

1. Elaborated upon the Purpose Statement to encompass more of the standard's content.
2. Added a Rationale text box to the section 4 - Applicability to explain the exclusion of substation facilities. Clarified 4.2.4 by adding specific boundary details.
3. Updated Requirement R1 and R2 to emphasize the "planning" time horizon as the applicable temporal context.
4. Elaborated upon the explanation in the Rationale text boxes for R1 and R2 to highlight the range of non-compliant performance.
5. Re-organized the content of Requirement R3 for improved readability.
6. Augmented Requirement R5 to include a "reliability objective".
7. Modified Requirement R6 and the associated VSLs for improved enforceability and for consistency in the units of measure between the Requirement and the associated VSLs.
8. Modified Requirement R7 and the associated VSLs for improved enforceability and for consistency in the units of measure between the Requirement and the associated VSLs.
9. Updated the Evidence Retention section in accordance with current guidelines.

Modifications incorporated into Draft 5 of FAC-003-2 in response to stakeholder comments include:

A. Removed reference to Active Transmission Line Right of Way (ROW).
B. Redefined the Glossary term for ROW to address Paragraph 734 of FERC Order 693 addressing the width of ROW to be maintained.
C. Redefined the Glossary term for Vegetation Inspection to include identifying hazards to the line inside the ROW.
D. Included the term referred to as "applicable lines" under Section 4.2 Facilities.

E. Removed Section4.4 and footnote 2 addressing "force majeure" and addressed the issue in new footnotes 2, 3 and 4.
F. In R1./R2 – M1/M2
   - Added reference "into the MVCD" (Minimum Vegetation Clearing Distance – MVCD) into the text.
   - Eliminated "types of encroachment" and added "The four types of failure to manage vegetation, in order of increasing severity."
   - In M1/M2, added a paragraph defining "later confirmation of a Fault by the TO as a real-time observation."
   - Added to the Rationale box types of failures to manage vegetation.
G. In R4, changed "qualified personnel" to TO.
H. In R5, added the term "is constrained from performing vegetation work" and referenced MVCD. Also removed reference to the 2003 northeast blackout from Rationale box
I. In R6, added the phrase " but no more than 18 months between inspections." Also added Footnote 3.
J. In R7, replaced major storms bullet with "circumstances that are beyond the control of a Transmission Owner." Also added Footnote 4 to this requirement.
K. In Additional Compliance Information
   - Category 2 was split into two parts recognizing Interconnection Reliability Operating Limits (IROL's) and Major Western Electric Coordinating Council (WECC) Transfer Paths.
   - Added Category 3 for Fall-ins from outside the ROW.
   - Category 4 was split into two parts recognizing IROL's and Major WECC Transfer Paths
L. Removed alternate versions of Violation Severity Levels (VSL's) for Requirements R1 and R2.
M. Deleted Table 3 from the Guidelines and Technical Basis section.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Michael Schiavone	National Grid	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Dean Ellis	Dynegy	NPCC	5
8.	Ben Eng	New York Power Authority	NPCC	4
9.	Brian Evans-Mongeon	Utility Services	NPCC	8
10.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
11.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
12.	Kathleen Goodman	ISO - New England	NPCC	2
13.	Chantel Haswell	FPL Group, Inc.	NPCC	5
14.	David Kiguel	Hydro One Networks Inc.	NPCC	1
15.	Michael R. Lombardi	Northeast Utilities	NPCC	1

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
16.	Randy MacDonald		New Brunswick System Operator	NPCC					2				
17.	Bruce Metruck		New York Power Authority	NPCC					6				
18.	Lee Pedowicz		Northeast Power Coordinating Council	NPCC					10				
19.	Robert Pellegrini		The United Illuminating Company	NPCC					1				
2.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Chuck Sheppard		BPA, Tx Vegetation/Access Road Mgmt	WECC					1				
2.	Steve Narolski		BPA, Tx Vegetation/Access Road Mgmt	WECC					1				
3.	Vince Ierulli		BPA, Transmission Line Design	WECC					1				
4.	Frank Weintraub		BPA, Transmission Line Design	WECC					1				
5.	Daniel Tuominen		BPA, Transmission Line Design	WECC					1				
6.	Joel Billings		BPA, Transmission Line Design	WECC					1				
7.	Michael Staats		BPA, Transmission Engineering	WECC					1				
8.	Don Swanson		BPA, Transmission Line Maintenance Technical Svcs	WECC					1				
3.	Group	Sasa Maljukan	Hydro One	X									
	Additional Member		Additional Organization	Region					Segment Selection				
1.	David kiguel		Hydro One Networks Inc.	NPCC					1				
2.	Patrick HOWE		Hydro One Networks Inc.	NPCC					1				
3.	Leslie KOCH		Hydro One Networks Inc.	NPCC					1				
4.	Jonathan MARRIOTT		Hydro One Networks Inc.	NPCC					1				
4.	Group	Richard Kafka	Pepco Holdings, Inc - Affiliates	X		X		X	X				
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Pat Byrne		Potomac Electric Power Company	RFC					1				
2.	Dave Paduda		Potomac Electric Power Company	RFC					1				
3.	Steve Benn		Delmarva Power & Light	RFC					1				
4.	Olivia Watts		Atlantic City Electric	RFC					1				
5.	Group	Joseph DePoorter	MRO's NERC Standards Review Subcommittee (nsrs)										X

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
Additional Member			Additional Organization	Region					Segment Selection				
1.	Mahmood Safi		OPPD	MRO					1, 3, 5, 6				
2.	Chuck Lawrence		ATC	MRO					1				
3.	Tom Webb		WPSC	MRO					3, 4, 5, 6				
4.	Jason Marshall		MISO	MRO					2				
5.	Jodi Jenson		WAPA	MRO					1, 6				
6.	Ken Goldsmith		ALTW	MRO					4				
7.	Dave Rudolph		BEPC	MRO					1, 3, 5, 6				
8.	Eric Ruskamp		LES	MRO					1, 3, 5, 6				
9.	Joseph Knight		GRE	MRO					1, 5, 6				
10.	Joe DePoorter		MGE	MRO					3, 4, 5, 6				
11.	Scott Nickels		RPU	MRO					4				
12.	Terry Harbour		MEC	MRO					1, 3, 5, 6				
13.	Carol Gerou		MRO	MRO					10				
6.	Group	Sam Ciccone	FirstEnergy			X	X	X	X				
Additional Member			Additional Organization	Region					Segment Selection				
1.	Rebecca Spach		FE	RFC					1				
2.	Katrina Schnobrich		FE	RFC					1				
3.	Doug Hohlbaugh		FE	RFC					1, 3, 4, 5, 6				
4.	Dave Folk		FE	RFC					1, 3, 4, 5, 6				
7.	Group	Michael Gammon	Kansas City Power & Light	X		X		X	X				
Additional Member			Additional Organization	Region					Segment Selection				
1.	Jennifer Flandermeyer		KCPL	SPP					1, 3, 5, 6				
2.	Duane Ansteate		KCPL	SPP					1, 3, 5, 6				
3.	Dean Beasley		KCPL	SPP					1, 3, 5, 6				
8.	Group	Mallory Huggins	NERC Staff										
Additional Member			Additional Organization	Region					Segment Selection				
1.	Robert Novembri		NERC	NA - Not Applicable					NA				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
2.	Gerry Adamski		NERC	NA - Not Applicable					NA				
3.	Joel deJesus		NERC	NA - Not Applicable					NA				
4.	Valerie Agnew		NERC	NA - Not Applicable					NA				
5.	Mike DeLaura		NERC	NA - Not Applicable					NA				
6.	Maureen Long		NERC	NA - Not Applicable					NA				
7.	David Taylor		NERC	NA - Not Applicable					NA				
8.	Herb Schrayshuen		NERC	NA - Not Applicable					NA				
9.	Group	Louis Slade	Dominion	X		X		X	X				
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Aaron Jonas			SERC					1				
2.	John Loftis			SERC					3				
3.	Mike Garton								5				
10.	Individual	Brandy A. Dunn	Western Area Power Administration	X									
11.	Individual	Jana Van Ness	Arizona Public Service Company	X		X		X	X				
12.	Individual	Steve Rueckert	Western Electricity Coordinating Council										X
13.	Individual	Luke Diruzza	Tampa Electric Company	X		X		X	X				
14.	Individual	Silvia Parada Mitchell	FPL FPL Corporate Compliance	X				X	X				
15.	Individual	JT Wood	Southern Company Transmission	X		X							
16.	Individual	Linwood Blacksmith	Tri-State Generation & Transmission	X									
17.	Individual	David Burke	Orange and Rockland Utilities, Inc.	X		X							
18.	Individual	Weston Davis	Central Maine Power Company, Iberdrola USA	X									
19.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
20.	Individual	Jonathan Appelbaum	The United Illuminating Company	X									
21.	Individual	Patrick Simons	Idaho Power Company	X									
22.	Individual	Sam Stonerock	Southern California Edison Company	X				X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
23.	Individual	Marty Berland	Progress Energy	X		X		X	X				
24.	Individual	John Bee	Exelon	X		X		X					
25.	Individual	Hugh Conley	Allegheny Power	X									
26.	Individual	Edward Davis	Entergy Services	X		X		X	X				
27.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				
28.	Individual	Gordon Rawlings	BC Hydro	X	X	X		X					
29.	Individual	Bill Rees	BGE Forestry Management	X									
30.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X					
31.	Individual	Bryan Taylor	Idaho Power	X									
32.	Individual	Anne Beard	PNM	X		X							
33.	Individual	James Sharpe	South Carolina and Gas	X		X		X	X				
34.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
35.	Individual	Andrew Z.Pusztai	American Transmission Company	X									
36.	Individual	Terry Harbour	MidAmerican Energy	X									
37.	Individual	Claudiu Cadar	GDS Associates	X									
38.	Individual	Joe Knight	Great River Energy	X		X		X	X				
39.	Individual	Kirit Shah	Ameren	X		X		X	X				
40.	Individual	Earl V. Burnside	PPL Electric Utilities	X		X							
41.	Individual	Jianmei Chai	Consumers Energy Company			X	X	X					
42.	Individual	Michael Pakeltis	CenterPoint Energy	X									
43.	Individual	E Hahn	MWDSC (METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA)	X									
44.	Individual	George Czerniewski	Consolidated Edison Company of New York Inc	X									

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
45.	Individual	James W. Smith	ITC Transmission										

1. The SDT replaced the defined term “Active Transmission Line Right of Way” with footnote number 2 that provides a description of “active transmission line ROW” and added Table 3, “Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW” to support that description. Do you agree? Please explain.

Summary Consideration:

Of 45 respondents, there is 1 abstention, 19 are in agreement, and 25 are in disagreement.

The major comment issues raised are:

1. The values used in Table 3 needs to be justified.
2. The definition of an active transmission line ROW ought to be a Glossary term.
3. The Table does not account for different structure designs and the term “centerline” is not applicable in all cases.

The VM SDT considerations for the major comment issues are:

1. The VM SDT added explanatory text in the Guideline and Technical Basis section.
2. Based on comments from 4th posting the SDT is revising the definition of ROW in the NERC Glossary.
3. Table 3 has been removed.

Some minor comment issues are:

1. Add distances for DC lines into Table 3.
2. The term and Table 3 needs further clarification.

The VM SDT considerations for the minor comment issues are:

1. Table 3 has been removed.
2. Table 3 has been removed.

	Organization	Yes or No	Question 1 Comment
1	MWDSC (METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA)		
2	Hydro One	No	A DC table for Table 3 similar to the MVCD table should be added.There should be a statement in Table 3 that is consistent with footnote number 2 stating that the minimum width of the Active Transmission Line ROW is either the full width of the easement or, if the easement is wider than the distances in Table 3, the minimum distances must not be less than the distances shown in the Table. The use of a minimum distance from the centerline of the circuit or structure is an incorrect measure to use for a set clearance distance of the active transmission right-of-way. The description does not take into account vertical versus horizontal design configuration. Consideration should be given for the type of construction as different construction types (H-Frame, Lat-tice towers, Monopole delta or vertical construction) will require different widths of a cleared right-of-way to provide the necessary openings for these circuits. A minimum distance for 345-kV is now set at 150 feet based on the minimum distances from centerline. This may be correct for certain H-Frame and Lattice Tower configurations but it is excessive for monopole situations. A single pole configuration with vertically aligned conductors does not need this full 150 foot width. It is strongly recommended that a minimum distance from conductor be used in place of a set distance from centerline. As long as there is at least 30 - 40 feet of clearance in the right-of-way from the outermost conductors (adjusted to account for maximum sway at mid-span for longer spans), then this is the distance that should be used to develop the right-of-way widths.For example, a monopole structure with vertically aligned conductors would result in a cleared active right-of-way width of only 80 feet (40 feet from conductor to edge of cleared active right-of-way) using the minimum distances from the conductors. There is no need to extend this distance another 35 feet (on each side) in order to obtain the full 150 foot width. This requirement is excessive and must be adjusted to account for line construction variations.

	Organization	Yes or No	Question 1 Comment
			Instead of using the term "Centerline" as referenced on Table 3, the use of "outer phase" or "phase closest to tree line" would be more appropriate. There is published literature using the term “cleared width” to indicate the distance from the outer phase to the tree line. This distance should be used in the Active ROW definition. The word easement is also used in the definition. Is there a reason the Active ROW only includes easements, not fee ownership, license or some other right to occupy and manage the ROW? Would Active ROW include “danger tree rights” on land? These questions need to be addressed in the standard (in text) and technical reference document (in graphics).
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
3	Allegheny Power	No	Allegheny Power strongly disagrees with the numbers or widths stated within Table 3. These numbers seem arbitrary and have no accompanying reasonable explanation as to their origin, basis, or other criteria noting the rationale for inclusion in this standard. This inclusion effectively prohibits a TO from establishing corridor widths less than the widths (which may be easily possible by utilizing various tower or structures heights or configurations) stated in Table 3 without placing the TO in extreme jeopardy of non-compliance issues from a falling off-corridor tree, during minor storm conditions as an example. Furthermore, this Table insinuates the TO has no ability to successfully manage vegetation WITH NO RESULTING OUTAGES or encroachments within the MVCD from off-corridor trees where corridors are less that the widths stated in Table 3.Allegheny Power suggests that the definition of the “Active Transmission line Right Of Way” be “the transmission line ROW corridor that is actively maintained as part of the entity's vegetation management plan.".
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
4	FPL Corporate Compliance	No	Although there is support for making Active Transmission Line Right of Way a clearly defined term, and the foundation for compliance with FAC-003-2, the distances in the table are arbitrary and are not supported by any scientific

	Organization	Yes or No	Question 1 Comment
			or engineering analysis. It is possible that such a table could be interpreted to define the minimum width of future lines. Different construction configurations require different ROW widths.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
5	PPL Electric Utilities	No	Centerline (CL) distances shown in Table 3 are shown as Minimal distances from CL. If utility is not able to define its ultimate ROW, due to CL agreement or other circumstances, these minimal distances may not be applicable and as such could result in non-compliance as written.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
6	Southern Company Transmission	No	Depending on the intent this may create a problem. We are concerned the addition of Table 3 could be interpreted to mean something completely different than what we believe to be its intention. Please consider alternate wording to Footnote 2: A strip or corridor of land that is occupied by active transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities. However, the active transmission line ROW cleared width it is not to be less than the width of the easement itself unless the easement exceeds distances as shown in Table 3 for various voltage classes.If the SDT determines keeping Table 3 is the appropriate course of action, we recommend clarifying its intent better; either in a footnote or in the title. Adding a footnote stating the Table is not applicable if the distance from the center line of the conductor to the right-of-way edge is less than the appropriate distance indicated in the table.Another option might be to add a statement to the title such as, "If the distance from the centerline of the circuit to the edge of the easement is less than the values in Table 3, that distance is considered active ROW".
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way.		

	Organization	Yes or No	Question 1 Comment
	Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
7	Ameren	No	Does this mean wider ROW easements will need to be acquired to be compliant or will this apply to ROW's for new circuits going forward?
	Response: Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
8	Progress Energy	No	In Applicability Section 4.4, "active transmission line ROW" is not capitalized indicating it is not a defined term, but Footnote 2 is effectively a definition for active transmission line ROW. However, in the first paragraph of Section 5 Background, Active Transmission Line Right-of-Way is capitalized indicating it's a defined term. It would seem cleaner to make "Active Transmission Line Right of Way" a formal NERC definition. Alternatively and at a minimum, Footnote 2 should be revised to say "An active transmission line ROW is a strip or corridor..." and also in Section 5 Background, "Active Transmission Line Right of Way" should be changed to no longer be capitalized.
	Response: Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
9	PNM	No	ROW easements vary according to land ownership therefore, potentially subjecting the utility to be liable for land outside of easement/ROW.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
10	Central Maine Power Company, Iberdrola USA	No	Table 3 distances may not be appropriate, for example table 3 should reflect a clearance zone based on construction type, topography, species, or growth rates. Table 3 could give the impression that the listed distances are the maximum, therefore suggest table 3 be removed or revised.The Active Transmisson Line Right-of-Way defination uses the word easement, which most likely would include danger trees in situations where danger removals

	Organization	Yes or No	Question 1 Comment
			are included in the the easement language. This would expand the scope of FAC 003 2 beyond the cleared right-of-way width.
	Response: The SDT agrees that Table 3 does not reflect the structural differences which directly determines the right of way width. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
11	Consumers Energy Company	No	Table 3 does not adequately address ROW width requirements based on the type of construction used for structures, especially for the two lower voltage classes, 69-138kV and 139-230 kV. Lines constructed on H-Frame structures have a much wider footprint across the ROW than do single pole construction and most steel tower construction types. The minimum ROW width listed in Table 3 for a 138 kV line constructed on a wooden H-Frame may put the outside conductor within MVCD under windy conditions due to wind displacement of conductors and trees.Consumers Energy recommends that Table 3 be modified to describe the minimum distance in the table is the vertical plane of the outside conductor to the edge of the active transmission ROW and therefore independent of the width of the structure construction type.
	Response: The SDT agrees that Table 3 does not reflect the structural differences which directly determines the right of way width. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
12	The United Illuminating Company	No	The definition has been altered. The last sentence "However, it is not to be less than the width of the easement itself unless the easement exceeds distances as shown in Table 3 for various voltage classes..." was added. The concept of the easement is confusing and not included in the Supplemental Reference. Table 3 of the standard is titled "Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW", no mention of easements. It is suggested that the definition state "strip or corridor of land that is occupied by active transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities. At a minimum the width is to be the distances as shown in Table 3 for various voltage classes."The

	Organization	Yes or No	Question 1 Comment
			proper location for the definition is in the Glossary.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
13	Dominion	No	The distances proposed in Table 3 - Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW may not be consistent with the centerline distances cleared and maintained by the TO. For example, a TO maintaining 75' from centerline for a 500kV circuit would be required to clear and maintain an additional 12.5' to meet the proposed standard's requirement. We suggest either allowing individual TOs to maintain active ROW widths consistent with their normal clearing/maintenance practices, going back to Draft 3's definition of Active Transmission Line Right-of-Way, or changing the footnote in Draft 4 to read:A strip or corridor of land that is occupied by active transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities. However, the portion of the ROW that has been cleared must at least meet design clearance requirements such as National Electric Safety Code or other design criteria, for the reliable operation of active facilities.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
14	BC Hydro	No	The footnote definition is ok but Table 3 is poorly developed. The voltage classes should be better segregated (e.g. nominal voltage 69kV, 138kV, 230kV, 287kV, 345kV, 500kV, 765kV) along with distances in feet and metres as Canadian utilities are metric. Also the table should include recommended right of way widths for single circuits. The assumption made in the footnote is that the legal easement is larger than in Table 3. However, as currently defined, some of the distances in Table 3 exceed statutory rights of way at our utility and exceed engineering standards as defined by the Canadian Standards Association - Overhead Systems (CAN/CSA C22.3 No. 1-6). Also, clearances will very much depend on line design (e.g. structure architecture such as flat, Post T, H-frame, steel lattice, and other variables

	Organization	Yes or No	Question 1 Comment
			such as ruling span length, conductor type used, etc.) To some degree this will vary quite a bit between utilities. As such Table 3 as currently presented is not workable.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
15	Exelon	No	The term "Centerline of the Circuit" in Table 3 is not defined. Until it is defined, there is no way to know if the standard is technically reasonable or whether existing circuits would be in violation of the standard and unable to operate. In addition, it is unclear what types of construction and span lengths were used to develop the distances for active right-of-way widths in Table 3. Furthermore, it is not clear whether Table 3 contains requirements against which compliance will be measured or best practice guidelines. Footnote 2, in the background section, compounds this ambiguity. In short, the lack of a definition for "Centerline" combined with Footnote 2 and Table 3 make this draft unclear and unenforceable. Exelon does not necessarily have easement widths for all transmission lines that equal those defined in Table 3 of this draft; This may require the acquisition of additional easements, if even possible.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
16	Northeast Utilities	No	The use of a minimum distance from the centerline of the circuit or structure is an incorrect measure to use for a set clearance distance of the active transmission right-of-way. Consideration should be given for the type of construction as different construction types (H-Frame, Lattice towers, Monopole delta or vertical construction) will require different widths of a cleared right-of-way to provide the necessary openings for these circuits. A minimum distance for 345-kV is now set at 150 feet based on the minimum distances from centerline. This may be correct for certain H-Frame and Lattice Tower configurations but it is excessive for monopole situations. A single pole configuration with vertically aligned conductors does not need this full 150 foot width. It is strongly recommended that a minimum distance from

	Organization	Yes or No	Question 1 Comment
			conductor be used in place of a set distance from centerline. As long as there is at least 30 - 40 feet of clearance in the right-of-way from the outermost conductors (adjusted to account for maximum sway at mid-span for longer spans), then this is the distance that should be used to develop the right-of-way widths.For example, a monopole structure with vertically aligned conductors would result in a cleared active right-of-way width of only 80 feet (40 feet from conductor to edge of cleared active right-of-way) using the minimum distances from the conductors. There is no need to extend this distance another 35 feet (on each side) in order to obtain the full 150 foot width. This requirement is excessive and must be adjusted to account for line construction variations.Instead of using the term "Centerline" as referenced on Table 3, the use of "outer phase" or "phase closest to tree line" would be more appropriate.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
17	Idaho Power Company	No	The way I interpret this, the new definition of active transmission line right of way takes away our ability to clear potential fall ins if they are outside of the active transmission line ROW>
	Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
18	CenterPoint Energy	No	There is no rationale provided for the “minimum distances” stated in Table 3, and they far exceed the ROW widths that CenterPoint Energy owns (typical total 100’ ROW width for 2-ckt 345kV line) for its current 345kV system, and as such, are open for misapplication and misinterpretation as an intended minimum standard for making a fall-in determination for R1 and R2 outside the legal limits of the utility. Table 3 should be deleted. If kept, there should be sufficient rationale included within the Guidelines and Technical Basis to explain how it was derived and how it is to be used within the Standard. CenterPoint Energy agrees with the removal of “active transmission line ROW” as a defined term; however, the footnote should be deleted as well since it attempts to create a definition which is not accurate, necessary or

	Organization	Yes or No	Question 1 Comment
			useful. Throughout the Standard, the phrase "active transmission line ROW" should be replaced with "transmission line ROW" to eliminate the qualifying term "active". In making a fall-in determination for R1 and R2, the limit should be "within the full extent of the Transmission Owner's transmission ROW as defined by easement, fee simple, or other legal rights" as discussed in the Guidelines and Technical Basis regarding the vegetation management maintenance approach. This places the determination of the width of the ROW for determination of fall-in violations clearly on the Transmission Owner and the within the limits of its legal rights to control the vegetation that has fallen into the line under R1 and R2.
	Response: The SDT thanks you for your comments. The SDT disagrees with the point that the TO should be required to clear the entire extent of legal rights. FERC Order 693 agreed that expansion easements needed to be adressed. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
19	Northeast Power Coordinating Council	No	There should be a statement in Table 3 that is consistent with footnote number 2 stating that the minimum width of the Active Transmission Line ROW is either the full width of the easement or, if the easement is wider than the distances in Table 3, the minimum distances must not be less than the distances shown in the Table.The use of a minimum distance from the centerline of the circuit or structure is an incorrect measure to use for a set clearance distance of the active transmission right-of-way. The description does not take into account vertical versus horizontal design configuration. Consideration should be given for the type of construction as different construction types (H-Frame, Lattice towers, Monopole delta or vertical construction) will require different widths of a cleared right-of-way to provide the necessary openings for these circuits. A minimum distance for 345-kV is now set at 150 feet based on the minimum distances from centerline. This may be correct for certain H-Frame and Lattice Tower configurations but it is excessive for monopole situations. A single pole configuration with vertically aligned conductors does not need this full 150 foot width. It is strongly recommended that a minimum distance from conductor be used in place of a set distance from centerline. As long as there is at least 30 - 40 feet of clearance in the right-of-way from the outermost conductors (adjusted to account for maximum sway at mid-span for longer spans), then this is the

	Organization	Yes or No	Question 1 Comment
			distance that should be used to develop the right-of-way widths.For example, a monopole structure with vertically aligned conductors would result in a cleared active right-of-way width of only 80 feet (40 feet from conductor to edge of cleared active right-of-way) using the minimum distances from the conductors. There is no need to extend this distance another 35 feet (on each side) in order to obtain the full 150 foot width. This requirement is excessive and must be adjusted to account for line construction variations.Instead of using the term "Centerline" as referenced on Table 3, the use of "outer phase" or "phase closest to tree line" would be more appropriate. There is published literature using the term “cleared width” to indicate the distance from the outer phase to the tree line. This distance should be used in the Active ROW definition. The word easement is also used in the definition. Is there a reason the Active ROW only includes easements, not fee ownership, license or some other right to occupy and manage the ROW? Would Active ROW include “danger tree rights” on land? These questions need to be addressed in the standard (in text) and technical reference document (in graphics).
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
20	Arizona Public Service Company	No	These clearances could exceed the permitted ROW’s on federal lands and the utility has no legal right to clear beyond those rights. In some cases the permitted ROW can exceed those distance and federal agencies could not allow you to clear beyond those clearances in this version.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
21	Entergy Services	No	This is very unclear, and creates much uncertainty as to how certain potential outage situations should be reported. Clarification language should be added within the Standard to help define and guide the TO's actions when an outage occurs from a location at a point that is less than the documented ROW boundaries (Easements) but greater than the ROW distances represented in Table 3. It is unclear which distance should guide our

	Organization	Yes or No	Question 1 Comment
			reporting actions........ROW Document Width, Table 3 ROW Widths, or the lesser of the two.......See scenarios / examples below for consideration to aid with clarification points:Example 1: If our documented ROW width for a 500kV line is 100' from centerline (200' total ROW width) and we have a fall in from 90' from centerline, do we report this as a Category 2 Outage due to the fact that it fell from within our ROW limits, or is it non-reportable due to the fact that it is located at a greater distance than 87.5' from the centerline of the ROW as listed in Table 3 in the Standard?Example 2: How does maintenance and outage reporting correlate with the example defined as follows.......You have a 230 kV line situated on one side of a 150' wide ROW that was initially cleared to a width that would accommodate 2 separate parallel transmission lines and structures. The second set of lines/structures have not yet been constructed, and the current Transmission line is situated on one side of the 150' ROW, and is being maintained to the edge of the actual ROW on the side of the ROW that it was constructed on (maintained to a distance of 50' from centerline that puts it at the legal edge of the ROW), but it has been typically maintained to a distance of approximately 60' from centerline to the inside portion/other side of the ROW (the side of the ROW that has never been cleared), but a tree falls into the line from approx 58' from centerline (2' within the 60' distance typically being maintained on that line).......would this be considered a Category 2 outage since it was approx 2' within the average width being maintained on that side of the ROW or would it not be reported due to the fact that it was located at a distance greater than 50' as indicated in Table 3??
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
22	Kansas City Power & Light	No	This needs to be a defined term since the Standard uses that as a basis for use with Table 3. Using this term as a footnote does not allow the industry to weigh in on its definition. Footnotes should not be used as a means of definition or clarification. Footnotes are for references to other sources of statements or documents that support a particular thought.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way.		

	Organization	Yes or No	Question 1 Comment
	Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
23	Xcel Energy	No	We believe Active Transmission ROW should be a defined term, not buried in a “footnote” of the “Other” section of a Standard. It still begs the question - what is an “active transmission facility”? Regarding the substance, overall we believe that the Active Transmission ROW should not include the new reference to Table 3. This newly added sentence in footnote 2, referencing Table 3, is confusing to interpret. If retained, please rephrase to make it clearer that a Transmission Owner never has to increase the size of its easement/land right to satisfy this table. As drafted, our team had various interpretations and it is unclear whether the intent is that a Transmission Owner has to increase its easement or acquire land to meet this requirement, or conversely if the easement is well beyond the values in Table 3, the Transmission Owner has to maintain that the entire easement or only the values in Table 3.”Active Transmission Right of Way” is still used in the first paragraph of the Background section.In total, we suggest that the definition of Activate Transmission ROW return to the version used in the prior draft and be placed in the definition section.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
24	ITC Transmission	No	We disagree with footnote comment as this adds confusion to the standard. Is a footnote considered part of the standard or not? The reference to table #3 is something new and has never been discussed or commented on prior to this revision and appears to be a bright line concept which we are in total disagree with.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
25	FirstEnergy	No	We do not support replacement of the term Active Transmission Line Right of Way with Footnote #2. Since the term "active transmission line ROW" is used in the requirements, compliance section, and VSLs, and since the drafting team has a very definite view of what this term means, the term should be a

	Organization	Yes or No	Question 1 Comment
			definition included in the NERC Glossary. Also, since ROW is defined in the NERC Glossary, it further supports the reasons this term should also be defined. Therefore, we suggest the team revert back to the Draft 3 proposed NERC Glossary term.Lastly, we do not support the addition of Table 3. We believe this adds unnecessary prescriptiveness to the requirements. It is also not clear if this Table was intended to be mandatory because the only reference in the table is in Footnote #2. If the SDT feels this table is a useful tool that should be included in the standard, then we suggest adding it to the Guidelines section as optional information. Also, reference to this Table 3 in the Active Transmission Line ROW definition should be removed.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
26	Tampa Electric Company	No	We have concern with the “Minimum Distances” as listed in Table 3. What analytical methodology, criteria and rationale was utilized to determine each recommended distance? In addition, we have concerns regarding the change to a pre-determined distance. This seems to be a major shift from the vegetation to conductor methodology employed previously and throughout this standard? NERC/FERC must recognize that while protecting and securing grid reliability, each utility must also balance the environmental, political, customer and economic issues and impacts which will occur with the implementation of the Table 3 clearances. We question whether this is the most responsible action to take given the current state of the economy as well as the environmental and political sensitivity impacts which will result. Tampa Electric questions whether Table 3 will improve System reliability. Since the inception of standard FAC-003-1 Tampa Electric has not had a Category 1 or Category 2 outage on our 230kV Transmission System. We don’t believe that the changes proposed to table 3 will improve overall service reliability. It is Tampa Electric’s opinion that each utility should define the width of its own Active Transmission line ROW. However, if such a table is to be utilized, Tampa Electric recommends the following changes or adjustments to Table 3.1. Expand the table to account for the various types of Transmission construction; i.e. vertical versus horizontal conductor configurations.2. Use a distance from the outermost conductor, not the centerline. This will account for construction type and better achieve a

	Organization	Yes or No	Question 1 Comment
			consistent clearance from conductors.3. We recommend reducing the distances in Table 3 by 12.5 feet for each voltage category. 4. Specify whether the voltage is based upon the design or operating voltage.5. Reformat the voltage ranges to 100kV - 200kV, 200kV - 300kV, 300kV - 400kV, etc. as an example; this would create a more appropriate range of voltages and clearance distances. The reformatted voltage ranges eliminate confusion. For example, under the current proposal it is unclear in which category a nominal 230kV line should be since sometimes such a line can operate at up to 232kV during low-load conditions.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
27	American Transmission Company	Yes	
28	BGE Forestry Management	Yes	
29	Great River Energy	Yes	
30	MidAmerican Energy	Yes	
31	NERC Staff	Yes	
32	Pepco Holdings, Inc - Affiliates	Yes	
33	South Carolina and Gas	Yes	
34	Western Electricity Coordinating Council	Yes	

	Organization	Yes or No	Question 1 Comment
35	GDS Associates	Yes	- ROW abbreviation comes prior to the full term (marked footnote prior to the full term as stated in 5. Background). Please make correction accordingly.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
36	Duke Energy	Yes	However, due to different design attributes of transmission lines, it may be better to change the distance in Table 3 from a centerline distance to a “Minimum Full Active Transmission Line ROW Width Distance”.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
37	Idaho Power	Yes	I support the description for the active right of way. However, I believe there needs to be a provision that addresses identifying potential hazards outside the active right of ways that may pose a risk to the transmission lines.
	Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
38	Manitoba Hydro	Yes	Please add metric equivalents in the standard.While it makes some aspects easier around pointing to what we need to keep "clear" to meet NERC rules - it does limit some of our flexibility to design lines and ROWs to your own standards. Also, the minimum only applies when you have easement larger than the minimums in table 3, and I would assume that does not relieve you of the responsibility to maintain ROWs appropriately if the design of your lines requires a wider ROW.
	Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		

	Organization	Yes or No	Question 1 Comment
39	Southern California Edison Company	Yes	SCE appreciates the SDT's efforts to replace the defined term with a set of minimum distances. However, the proposed new Table 3 appears to assume a horizontal configuration of transmission lines. Thus, it would appear that those lines configured vertically (for example, two circuits on opposite sides of a tower), the "active right of way" required would be at least twice as large as that for horizontal lines. SCE respectfully recommends a footnote be added to Table 3 that allows the TO to recalculate the active right of way for lines in a vertical configuration, based on a horizontal line configuration.
	Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
40	Western Area Power Administration	Yes	Suggest using a total right-of-way width in Table 3 rather than a distance measured from centerline.
	Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
41	Tri-State Generation & Transmission	Yes	Table 3 should be referenced as a guideline only.
	Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
42	MRO's NERC Standards Review Subcommittee (nsrs)	Yes	The NSRS agrees in whole to the question but has the SDT taken into consideration the difference in ROW may be different in Urban and Rural settings?
	Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		

	Organization	Yes or No	Question 1 Comment
43	Consolidated Edison Company of New York Inc	Yes	The same verbiage in footnote number 2 should appear below Table 3 to avoid any confusion.
	Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
44	Orange and Rockland Utilities, Inc.	Yes	There should be a statement in Table 3 that is consistent with footnote number 2 stating that the minimum width of the Active Transmission Line ROW is either the full width of the easement or, if the easement is wider than the distances in Table 3, the minimum distances must not be less than the distances shown in the Table.
	Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
45	Bonneville Power Administration	Yes	This distance is reasonable in the table, but due to widely varying designs of structures it does not give a relationship of the outside wire to edge of ROW. It should be noted as outside wire, phase or conductor to edge of ROW.In addition, the effective date should allow transmission owners time to achieve this distance, perhaps one cycle.
	Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		

2. In response to comments received regarding the terms “reasonable” and “human errors/human activity”, the SDT modified the Other Section and Background Section. Do you agree? Please explain.

Summary Consideration:

Of 45 respondents, there are 3 abstentions, 38 are in agreement, and 4 are in disagreement.

The major comment issues raised are:

1. **Of the 4 in disagreement, only NERC believes “force majeure” statement is not necessary.**
2. **Three respondents believe the “force majeure” statement should be expanded to include Federal, State, Regulatory and legal interference.**

The VM SDT considerations for the major comment issues are:

1. a) The SDT believes this language is appropriate for this standard due to the many factors related to vegetation that are truly outside the TO’s control. Unlike the vast majority of other NERC standards, implementation of FAC-003 is not under the absolute control of the utilities. These influences range from landowner and agency obstacles to weather events, and as such the SDT believes the force majeure provisions should be applicable. The recognition of this provision is also supported by 90% of the industry. An attempt at similar language is contained in version 1 but it is ambiguous and lacks clarity. This language adds clarity and reduces the opportunity for mis-application. Further, TO’s who elect to invoke “force majeure” must have supporting evidence of such action. The lack of a force majeure section means a Transmission Owner would have a violation of a Requirement, even if the penalty might have been mitigated by the circumstances.

   b) However, the SDT moved the force majeure from applicability to a footnote (Footnote 2) based on comments concerning the structure of NERC standards. The footnotes are referenced in R1, R2, and R7. In R6, an exclusion clause was added in Footnote 3.

3. The SDT recommends no expansion. The “force majeure” provision is intended to recognize circumstances that are completely outside the TO’s control. Federal, State or regulatory interference is certainly a barrier but there are actions available to mitigate such interference. The TO should be aware of such interference and should take whatever corrective actions necessary, up to and including re-rating or de-energizing the line, to avoid a vegetation conflict.

Some minor comment issues are:

1. **One respondent would like to specifically define wind speed.**
2. **Two respondents suggested moving the language elsewhere in the standard.**

The VM SDT considerations for the minor comment issues are:

1. **The SDT recommends no change. Wind speed is addressed by “fresh gale”.**
2. **The SDT moved it to a footnote.**

	Organization	Yes or No	Question 2 Comment
1	MWDSC (METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA)		
2	Western Electricity Coordinating Council		
3	Central Maine Power Company, Iberdrola USA		No comment suggested.
4	NERC Staff	No	NERC staff does not support the language in the Other Section. Staff believes that the force majeure provision is unnecessary and calls into question whether NERC and the regions have enforcement discretion to take such things into account in applying other standards that do not include this type of provision.
	Response: The SDT thanks you for your comments. The SDT believes this language is appropriate for this standard due to the many factors related to vegetation that are truly outside the TO’s control. Unlike the vast majority of other NERC standards, implementation of FAC-003 is not under the absolute control of the		

	Organization	Yes or No	Question 2 Comment
	utilities. These influences range from landowner and agency obstacles to weather events, and as such the SDT believes the force majeure provisions should be applicable. The recognition of this provision is also supported by 90% of the industry. An attempt at similar language is contained in version 1 but it is ambiguous and lacks clarity. This language adds clarity and reduces the opportunity for mis-application. Further, TO's who elect to invoke "force majeure" must have supporting evidence of such action.		
5	BGE Forestry Management	No	Suggest including in "4.4. Other" a phrase referencing government interference, such as "Federal, State or other regulatory interference, including legal or other legislative actions, that prevents performance to comply with this reliability standard."
	Response: The SDT thanks you for your comments. The "force majeure" provision is intended to recognize circumstances that are completely outside the TO's control. Federal, State or regulatory interferrence is certainly a barrier but there are actions available to mitigate such interference. The TO should be aware of such interference and should take whatever corrective actions necessary, up to and including re-rating or de-energizing the line, to avoid a vegetation conflict.		
6	Kansas City Power & Light	No	The theme of the "Other" section are the conditions for excluding applicable transmission facilities under certain conditions. Recommend the Drafting Team consider renaming this section to "Exclusions". In addition, the term, "Active Transmission Line Right-of-Way" is capitalized in the "Background" section. If it is determined this term should not be a definition, then this should be lower case.
	Response: The SDT thanks you for your comments. The recommendation does not materially change the "force majeure" provision and the SDT does not recommend any change. The SDT did modify the ROW definition in response to industry concerns. Capitalization is now appropriate.		
7	Xcel Energy	No	Xcel Energy urges the retention of the word "reasonable" as a modifier to "control" in Introduction, Section 4.4. The concept that a Transmission Owner should exercise reasonable control is sensible, and is of some aid in countering claims that any incident could be prevented. For example, in Colorado, the transmission of electricity has been judicially found to be subject to the highest degree of care. Without the inclusion of the word "reasonable," Xcel Energy could possibly be faced with a claim that for the exceptions set forth in Introduction, Section 4.4, to apply, the circumstances would have to be "beyond the control (using the highest degree of care) of

	Organization	Yes or No	Question 2 Comment
			Xcel Energy." Retention of "reasonable" helps counter such claims. Since this section appears to lean toward legal language, the use of the term “reasonable” is better suited for the goal of this section.
	Response: The SDT thanks you for your comments. While we understand the concerns, the word reasonable is ambigous and open to intrepretation and therefore not an appropriate modifier to the language.		
8	Allegheny Power	Yes	
9	Ameren	Yes	
10	American Transmission Company	Yes	
11	Arizona Public Service Company	Yes	
12	Bonneville Power Administration	Yes	
13	Consolidated Edison Company of New York Inc	Yes	
14	Consumers Energy Company	Yes	
15	FPL Corporate Compliance	Yes	
16	Dominion	Yes	
17	Duke Energy	Yes	

	Organization	Yes or No	Question 2 Comment
18	Entergy Services	Yes	
19	Exelon	Yes	
20	GDS Associates	Yes	
21	Hydro One	Yes	
22	Idaho Power Company	Yes	
23	ITC Transmission	Yes	
24	Manitoba Hydro	Yes	
25	MidAmerican Energy	Yes	
26	Northeast Power Coordinating Council	Yes	
27	Northeast Utilities	Yes	
28	Orange and Rockland Utilities, Inc.	Yes	
29	Pepco Holdings, Inc - Affiliates	Yes	
30	PNM	Yes	
31	PPL Electric Utilities	Yes	
32	Progress Energy	Yes	

	Organization	Yes or No	Question 2 Comment
33	South Carolina and Gas	Yes	
34	Southern Company Transmission	Yes	
35	The United Illuminating Company	Yes	
36	Tri-State Generation & Transmission	Yes	
37	Western Area Power Administration	Yes	
38	Great River Energy	Yes	GRE believes that the new definition provides greater clarity with respect what does not constitute a compliance violation versus the previous version.
	Response: The SDT thanks you for your comments and we are in agreement.		
39	CenterPoint Energy	Yes	No preference.
	Response:		
40	Southern California Edison Company	Yes	SCE generally agrees with the information contained in Part 5 - Background. However, we question the value of placing a rationale within the body of the standard. SCE respectfully recommends that the revised "Background" information be added to the beginning of the "Guidelines and Technical Basis," which also includes explanations for various standard segments.
	Response: The SDT thanks you for your comments. It is not specific to "force majeure" and is best answered in general comments.		
41	MRO's NERC Standards Review	Yes	The NSRS believes that the new definition provides greater clarity with respect what does not constitute a compliance violation versus the previous

	Organization	Yes or No	Question 2 Comment
	Subcommittee (nsrs)		version.
	Response: The SDT thanks you for your comments and we are in agreement.		
42	Tampa Electric Company	Yes	These changes add improved clarity and defintion to this section.
	Response: The SDT thanks you for your comments and we are in agreement.		
43	Idaho Power	Yes	This will allow the utilities to address conditions that are within their control.
	Response: The SDT thanks you for your comments and we are in agreement.		
44	FirstEnergy	Yes	While we agree with the changes proposed, we would recommend that the list contained in the "Other" section should be revised to include judicial actions such as injunctions. While this is not a natural occurring situation, it is certainly one that will prevent an entity from removing vegetation when needed or desired.
	Response: The SDT thanks you for your comments. The "force majeure" provision is intended to recognize circumstances that are completely outside the TO's control. Legal and judicial actions are certainly a barrier but there are other corrective actions available to mitigate such interference. The TO should be aware of such interference and should take whatever actions necessary, up to and including re-rating or de-energizing the line to avoid a vegetation conflict.		
45	BC Hydro	Yes	Yes but there should be more commentary around exceptions. You should get away from certain descriptive terms and be more empirical when you can to avoid ambiguity. For example "Fresh Gale" on the Beaufort Scale is not common as there are several variants to this scale and on some scales is defined as "Gale". So do you mean winds of 39-46 mph (62-74 kmh) or greater wind speed? If so, why not state that?
	Response: The SDT thanks you for your comments. The "force majeure" provision is not intended to address every possible exclusion but to be a general statement intended to recognize circumstances that are completely outside the TO's control.		

3. In response to comments received regarding the language in M1 and M2, the SDT modified the first bulleted item and added a sentence to the end of the paragraph in M1 and M2. Do you agree? Please explain.

Summary Consideration:

Of 45 respondents, there are 2 abstentions, 27 are in agreement, and 16 are in disagreement.

The major comment issues raised are:

1. **Definition of "qualified personnel".**
2. **Confusion around "real time observation of an encroachment into the MVCD" and documentation required to report a violation or attest that a violation did not occur. Also issues regarding an encroachment with no fault and/or momentary fault as being a violation.**

The VM SDT considerations for the major comment issues are:

1. **SDT changed the language to "confirmation by Transmission Owner".**
2. **Considered language proposed by Duke in comment 16 and adopted and modified by SDT.**

A minor comment issue is:

1. **The inclusion of examples in the requirement instead of the rationale box.**

The VM SDT consideration for the minor comment issue is:

1. **The SDT changed the language to "confirmation by Transmission Owner".**

	Organization	Yes or No	Question 3 Comment
1	MWDSC (METROPOLITAN		

	Organization	Yes or No	Question 3 Comment
	WATER DISTRICT OF SOUTHERN CALIFORNIA)		
2	Xcel Energy		No comments/no position
3	GDS Associates	No	- Need to specify who qualifies as “qualified personnel” to observe the vegetation condition.
	Response: Thank you for your comment. The SDT changed the wording to confirmation by the Transmission Owner.		
4	Hydro One	No	A clarification for M1 is needed regarding whether entities will have to attest to the fact that there has never been an encroachment in the MVCD.
	Response: Thank you for your comment. It is not the intent of this standard for entities to be required to prove a negative. The SDT believes the proposed language does not imply that an entity will be required to prove that an encroachment has not occurred.		
5	Northeast Power Coordinating Council	No	A clarification for M1 is needed regarding whether entities will have to attest to the fact that there has never been an encroachment in the MVCD.
	Response: Thank you for your comment. It is not the intent of this standard for entities to be required to prove a negative. The SDT believes the proposed language does not imply that an entity will be required to prove that an encroachment has not occurred.		
6	PPL Electric Utilities	No	As written M1 requires evaluation of condition by “qualified person” but no definition of qualified person given. Should be more direct and point to physical evidence of vegetation encroachment into MVCD, i.e. burned vegetation.
	Response: Thank you for your comment. The SDT changed the wording to confirmation by the Transmission Owner. It is not the intent of this standard for entities to be required to prove a negative. The SDT believes the proposed language does not imply that an entity will be required to prove that an encroachment has not occurred.		

	Organization	Yes or No	Question 3 Comment
7	CenterPoint Energy	No	CenterPoint Energy does not believe a performance based requirement should require evidence of processes and procedures to demonstrate compliance. However, if the majority of industry commenters agree with the SDT's approach, CenterPoint Energy has several concerns.Assuming R1.1 and R2.1 regarding observations of encroachments are not deleted from the Standard, then only the first paragraph regarding forms of evidence is helpful and necessary. The second paragraph is not relevant or necessary. The special qualification of Sustained Outage should be contained in R1 and R2, not M1 and M2. Also, the reference to a "Fault" in M1 and M2 instead of a "Sustained Outage" changes the scope of what is specified in R1 and R2 which is not reasonable. A "Fault" can be associated with a Momentary Outage or a Sustained Outage. The scope of R1 and R2 is specific to Sustained Outages.
	Response: Thank you for your comment. The SDT chose the word "fault" as it is a NERC defined term. A fault associated with vegetation indicates that encroachment into the MVCD occurred.		
8	Arizona Public Service Company	No	Do not agree with real-time observation. Utility can use technology to determine all rated conditions if a tree related outage occurred.
	Response: Thank you for your comment. The real-time observation reference applies to cases where vegetation encroaches into the MVCD but flash-over has not occurred. Enroachment into the MVCD where no fault occurs is the least severe violation of the requirement.		
9	MidAmerican Energy	No	Examples should be moved to the rationale boxes to avoid confusion on what is required and what is an example. All rationale boxes should have a disclaimer to the effect saying "For guidance only, not for enforcement".
	Response: Thank you for your response. Examples were included in the Requirement at the response of NERC staff to add clarity. By definition, verbiage within the rationale boxes are for guidance and are not enforcable.		
10	Kansas City Power & Light	No	In response to the informal comment period, the SDT is clear that it believes the use of encroachment as a basis for determining the effectiveness and compliance of a vegetation management program. The purpose of this Standard is to identify the criteria for effective monitoring of vegetation in

	Organization	Yes or No	Question 3 Comment
			transmission right-of-way and to take appropriate actions when that monitoring identifies the need to “clear” vegetation to prevent potential transmission facility outages resulting from contact with vegetation. These proposed Measures as written do not give credit to the Transmission Owners for effectively monitoring their systems and taking appropriate actions in regard to vegetation clearing. Why does it make sense to punish and penalize a Transmission Owner for discovering an encroachment when they take the appropriate actions to remedy the condition before any facility outage occurs that results in compromising the reliability of the Bulk Electric System? These Measures and Standard should recognize the good practices of effective response to a vegetation condition and penalize ineffective response. Highly recommend the SDT consider including appropriate language to recognize effective remedial actions by Transmission Owners and by doing so, recognize effective efforts instead of punishing them.In addition, proving encroachments have not occurred will pose audit challenges in determining that encroachments have not occurred for the Auditors as well as Registered Entities. If no encroachments occur, then there is nothing to report or record. This is a weak platform to stand compliance on. Facility interruption events caused by vegetation contacts is definitively measurable and recordable. Recommend the SDT reconsider the concept of compliance with FAC-003 on the basis of sustained outages.
	Response: Thank you for your comment. The real-time observation reference applies to cases where vegetation encroaches into the MVCD but flash-over has not occurred. Enroachment into the MVCD where no fault occurs is the least severe violation of the requirement. It is not the intent of this standard for entities to be required to prove a negative. The SDT believes the proposed language does not imply that an entity will be required to prove that an encroachment has not occurred.		
11	BGE Forestry Management	No	M1 & M2 bullet: “Real-time observation of any MVCD encroachments.” implies that real-time observation of vegetation encroachment ensures reliable operation the Bulk Electric System. The reliability standard objective states;”To improve the reliability of the electric Transmission system by preventing those vegetation related outages that could lead to Cascading.”However, real time observation of current operating conditions provides no assurance that vegetation will not lead to outages. BGE recommends removing the language. If an inspector finds vegetation encroaching into the MVCD during a visual inspection he / she should

	Organization	Yes or No	Question 3 Comment
			immediately initiate an Immediate Threat Notification. Therefore, this measure has no value.
	Response: Thank you for your comment. The real-time observation reference applies to cases where vegetation encroaches into the MVCD but flash-over has not occurred. Enroachment into the MVCD where no fault occurs is the least severe violation of the requirement.		
12	PNM	No	Needs a definition of Real Time Observations
	Response: Thank you for your comment. The SDT believes that "Real Time" observations (the actual time during which the observation occurs) is sufficiently clear.		
13	Consumers Energy Company	No	None of the three examples of acceptable forms of evidence provided in the revision prove that a Transmission Owner actively managed vegetation to prevent encroachment into the MVCD. The Measure should require proof of active ROW clearing activity per the transmission vegetation management plan, such as invoicing or crew field reports or vegetation inspection data from the annual vegetation inspection.
	Response: Thank you for your comment. The SDT would suggest you refer to R6 and R7, which addresses evidence of an annual vegetation inspection and work plan.		
14	BC Hydro	No	Overall, the definition of these measures is improved over draft 3. However, the standard should better define who a "qualified person" is and who has the authority to make attestations. R1 and R2 could be better defined relative to the standard definitions in section 4.2 as to what voltage levels in R2 are part of the standard and what is excluded. That is:R1 is any circuit that is an element of an IROL or WECC transfer path regardless of the transmission voltage.R2 is any circuit >200kV which is not an element of an IROL or WECC transfer path.Lower voltage circuits that do not fit the R1 definition are not part of this standard.
	Response: Thank you for your comment. The SDT changed the wording to confirmation by the Transmission Owner. R1 and R2 intentionally differentiate between the components of the transmission system that are part of the IROL or WECC Transfer Path and the BES. The SDT believes that violations in the IROL or WECC Transfer Paths pose a greater risk of cascading events, and therefore carry higher VSLs.		

	Organization	Yes or No	Question 3 Comment
15	Central Maine Power Company, Iberdrola USA	No	Recommend SDT create two measures one measure if a tree violated the MVCD and no outage occurred and second measure and severity level if an outage occurred
	Response: The SDT believes that enroachments into the MVCD where no fault occurs are a violation to the standard and should be included in R1 and R2.		
16	Duke Energy	No	The last sentence of this modification could be misinterpreted by a compliance representative to imply that all Faults must be investigated to eliminate or confirm vegetation as the cause of the fault. There are several sources (e.g. lightning, wind-blown debris) of Faults and several appropriate operational responses, some of which may not include field investigations, depending on the circumstances surrounding each Fault. Thus, the current wording is gray and should be modified to aid industry's understanding and thus to ensure compliance.The interpretation we suggest may not be obvious, but our experience with previous interpretations of certain facets of FAC-003-01 would indicate the need to better define the expectation.A potential modification to the last sentence of M1/M2 could be:If a later confirmation of a Fault by a qualified person shows that a vegetation encroachment within the MVCD has occurred, this shall be considered the equivalent of a Real-time observation.
	Response: Thank you for your comment. The SDT agrees with your recommendation and has adopted the proposed language. The SDT believes that faults that occur on applicable lines included in R1 and R2 should be investigated to determine if the cause was vegetation related. If an entity can determine to their satisfaction, through documentable means such as through technology or other sources, that the fault was caused by some other reason (i.e. lightning), it is the entity's decision whether or not to investigate further.		
17	FPL Corporate Compliance	No	The measure is adding to the requirement. The measure should define how a requirement is met and not interpret or add to the requirement, otherwise this will add to confusion, instead of clarity, which should be the goal of any revised reliability Standard.Also, the measure implies that a fault investigation must be done. As written, momentary outages are included, and a fault investigation should not be required for momentary outage.It also places the same weight of violation on a momentary outage as it does a Sustained outage, which appears on its face not to appropriate nor

	Organization	Yes or No	Question 3 Comment
			necessary to meet the goal of FAC-003-2. In addition, an outage investigation is not a finite process that produces identical homogenous results every time. Of particular concern is the possibility that should a Transmission Owner have one or more momentary outages and not find the cause, then later have another outage (Sustained or Momentary), such a finding appears to lead to a multiple violation. This is inconsistent with focusing requirements on reliability risks to the bulk electric system.
	Response: Thank you for your comment. A fault caused by the grow-in, fall-in, or blow-in of vegetation on the active right-of-way is a violation of the requirements regardless of whether the fault was momentary or sustained. Based on other comments, the SDT has modified the language in M1/M2.		
18	NERC Staff	No	With respect to both M1 and M2, NERC staff finds the “acceptable forms of evidence” incomplete. To assess compliance, the auditors would also need to see the processes and procedures identified under Requirement R3 and the annual work plan under Requirement R7 to see how the entity planned to prevent sustained outages and what the entity had done to implement that plan. Finally, what is the purpose of the following sentence?: “If an investigation of a Fault by a qualified person confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered a Real-time observation.” Recommend adding each report of a real-time observation of encroachment into the MVCD to the periodic data submittal.
	Response: Thank you for your comment. The SDT believes that an attempt to list all “acceptable forms of evidence” would be difficult, as entities employ a myriad of documentation types. The SDT agrees that an auditor would need to see the processes and procedures indentified under R3 and R7 to perform an audit. An auditor with an understanding of vegetation management would be able to validate “acceptable forms of evidence” as part of compliance audit process. Real time observations of an encroachment into the MVCD is a violation of the standard and should be documented and self-reported. The RE’s currently require periodic reporting.		
19	Allegheny Power	Yes	
20	Ameren	Yes	
21	American	Yes	

	Organization	Yes or No	Question 3 Comment
	Transmission Company		
22	Bonneville Power Administration	Yes	
23	Consolidated Edison Company of New York Inc	Yes	
24	Dominion	Yes	
25	Exelon	Yes	
26	Idaho Power	Yes	
27	Idaho Power Company	Yes	
28	ITC Transmission	Yes	
29	Manitoba Hydro	Yes	
30	MRO’s NERC Standards Review Subcommittee (nsrs)	Yes	
31	Northeast Utilities	Yes	
32	Orange and Rockland Utilities, Inc.	Yes	
33	Pepco Holdings, Inc – Affiliates	Yes	

	Organization	Yes or No	Question 3 Comment
34	Progress Energy	Yes	
35	South Carolina and Gas	Yes	
36	Southern Company Transmission	Yes	
37	The United Illuminating Company	Yes	
38	Tri-State Generation & Transmission	Yes	
39	FirstEnergy	Yes	Although we agree with the language of M1 and M2 for the proposed R1 and R2 in the standard being balloted, we support the alternate versions of R1 and R2 (see comments in Question 6) and wish to see M1 and M2 developed for the alternate R1 and R2.
	Response: Thank you for your comment.		
40	Great River Energy	Yes	GRE agrees with the revisions made to this standard since the last posting and requests clarification on what constitutes a qualified person.
	Response: Thank you for your comment. The SDT changed the wording to confirmation by the Transmission Owner.		
41	Western Electricity Coordinating Council	Yes	however the statement of acceptable forms of evidence implies that a dated attestation alone could provide evidence of compliance. An attestation alone would not represent sufficient evidence to support a conclusion of compliance with encroachment limits only of the absence of an outage.
	Response: Thank you for your comment. Real time observations of an encroachment into the MVCD is a violation of the standard and should be documented and self-reported.		

	Organization	Yes or No	Question 3 Comment
42	Western Area Power Administration	Yes	However, the last sentence added to the measure is imprecise and introduces undesirable subjectivity and confusion to the process for determining a compliance violation.
	Response: Thank you for your comment. Based on the recommendation from several commentors, the last sentence in M1/M2 has been modified.		
43	Southern California Edison Company	Yes	SCE generally agrees with the revisions to M1 and M2, however we would suggest the last sentence of the second paragraphs in both M1 and M2 be modified to read: M1- Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. If an investigation of a Fault, by a qualified person, confirms that a vegetation encroachment, as described in R1 items 2-4 (above), occurred within the MVCD occurred, then it shall be considered a Real-time observation.M2- Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. If an investigation of a Fault, by a qualified person, confirms that a vegetation encroachment, as described in R2 items 2-4 (above), occurred within the MVCD occurred, then it shall be considered a Real-time observation.
	Response: Thank you for your comment. Based on the recommendation from several commentors, the last sentence in M1/M2 has been modified.		
44	Tampa Electric Company	Yes	These changes allow for qualified review of field findings.
	Response: Thank you for your comment.		
45	Entergy Services	Yes	We agree, IF the determination is made by a Qualified Person to have been caused by vegetation breaking the MVCD (if not breaking MVCD in real time when observed) based on close observation/inspection and hard evidence that a Flashover occurred, and that there is no evidence that the issues spotted on the tree were caused by environmental or biological symptoms or stressors of the tree in question. Hard evidence has to be present to classify

	Organization	Yes or No	Question 3 Comment
			the item as a vegetation outage if the tree is not within MVCD when the real time observation is made.....an assumption cannot be made that vegetation was the cause of an outage if the tree is situated at a distance that is greater than MVCD when observed unless there is hard evidence supporting the flashover as determined by a qualified person.
	Response: Thank you for your comment.		

4. In response to comments received that requirement R3 is deficient in detail, the SDT modified the requirement. Do you agree? Please explain.

Summary Consideration:

Of 45 respondents, there are 32 in agreement, 12 in disagreement and1 abstention.

The major comment issues raised are:

1. **The additional wording placed in the requirement after the first sentence adds confusion to the extent of documentation that will be required.**
2. **The use of the phrase "incorporate the dynamics" adds confusion to the requirement.**

The VM SDT considerations for the major comment issues are:

1. **The response pointed out that the reason that the additional wording was inserted was due to the numerous comments from the previous posting that the requirement needed more specificity.**
2. **The SDT agreed with some suggested wording to replace the phrase "incorporate the dynamics" and revised the requirement accordingly.**

Some minor comment issues are:

1. **One commenter questioned the use of the word "intent" in the rationale.**
2. **One commenter questioned the language of the measure.**
3. **One commenter was concerned that the removal of the programmatic details renders the requirement less auditable and questionably effective.**

The VM SDT considerations for the minor comment issues are:

1. **The wording in the rationale was changed to eliminate the word "intent".**
2. **In the response to the commenter questioning the language of the measure, the SDT explained that the focus of the measure is on the logic test of the Transmission Owner's vegetation maintenance program.**

3. In response to the commenter concerned about the programmatic details being removed, the SDT responded by explaining various ways that this requirement could be audited and further explained the main focus of the requirement.

	Organization	Yes or No	Question 4 Comment
1	MWDSC (METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA)		
2	GDS Associates	No	- We suggest to eliminate / change the word “dynamics” because can create confusion with regards to the extent of documentation that has to be prepared.- Requirement should clearly state the criteria as in the maximum design (rating) or maximum operat
	Response: The SDT thanks you for your comment. The intent of the more detailed wording of R3 in this version of the Standard is to make sure that the Transmission Owner adequately documents and demonstrates that it understands the complex relationship of conductor movement under thermal and wind load and vegetation growing and moving in proximity to the line. In light of your comment, and similar comments from others, the SDT has revised the wording of R3. We feel that this change will alleviate any perceived confusion.		
3	PPL Electric Utilities	No	As written, R3 now requires documentation of conductor dynamics as related to ratings and rated operational conditions. Not clear how this information is to be presented and documented and how vegetation conditions that exist are to be documented to provide evidence that management processes and procedures are adequate to prevent encroachment into MCVD.
	Response: The SDT thanks you for your comment. The Technical Reference Document attempts to provide further explanation, along with examples, of how to present this information. While this information is not in the Standard itself, the supplemental information in the Technical Reference Document should help the Transmission Owner understand the SDT’s intent for the requirement. Also, The SDT has revised the wording in R3 and has removed the word “dynamics”.		

	Organization	Yes or No	Question 4 Comment
4	Great River Energy	No	GRE does not believe that the new specificity that has been added to R3 will improve the reliability of the BES. It is our opinion that the requirement would have been clearer if it had ended after the first sentence. The additional language after the first sentence does not improve clarity.In measures for other requirements the SDT has done a very good job of stating and clarifying (in their opinion) what acceptable forms of evidence are. M3 would benefit from this type of clarification.
	Response: The SDT thanks you for your comment. The previous version of the Standard was crafted very much as you suggest. Many commenters disagreed with this approach, which led to the SDT crafting this more verbose version.		
5	Kansas City Power & Light	No	It is unclear that this requirement may utilize the industry practice of "ruling span" methods to determine the vegetation clearances for a transmission facility. "Ruling span" methods are used to determine the construction design for transmission facilities and includes maintaining safe clearance distances. This requirement could be interpreted as being applied to every individual span to determine vegetation clearances for a transmission facility which would not be practical.
	Response: The SDT thanks you for your comment. The intent of R3 in this version of the Standard is to make sure that the Transmission Owner adequately documents and demonstrates that it understands the complex relationship of conductor movement under thermal and wind load and vegetation growing and moving in proximity to the line. It leaves the decision to the Transmission Owner how to satisfy this "competency based" requirement. While a Transmission Owner could certainly take the approach that each individual span be addressed separately, it is also possible for a Transmission Owner to have a specific "vegetation maximum height" approach, based on the minimum ground clearance specification of an entire line. Either approach would satisfy this requirement.		
6	MidAmerican Energy	No	MidAmerican supports the additional detail the R3 should end after the first sentence. The additional detail should be moved to the rationale box as additional guidance.
	Response: The SDT thanks you for your comment. If we understand your comment, the reason that R3 has greater detail was due to comments received after the last posting. The SDT felt compeled to add this additional information.		

	Organization	Yes or No	Question 4 Comment
7	Xcel Energy	No	R3 requires the Transmission Owner to have a documented process that shall contain certain items. Please bulletize these items for clarity.Additionally, the measure for this requirement indicates that the process document elements 'prevent' encroachment. It is presumed that the elements identified in the requirement are what need to be addressed in order to minimize the likelihood of encroachment. Essentially, M3 should be reworded to state "The procedures, processes, or specifications provided incorporate the elements identified in R3 (dynamics of a transmission line conductor's...)
	Response: : The SDT thanks you for your comment. The SDT feels that the requirement is adequate in a non-bullet form. R3 has been revised to clarify the intent of this "competency based" requirement. The measure for this requirement should be a "logic" test looking at the methodology that the Transmission Owner uses in order to determine what vegetation actions need to take place. The Technical Reference Document gives examples of several ways to satisfy this requirement. The SDT feels that the measure as stated is adequate.		
8	Southern California Edison Company	No	SCE prefers the Draft 3 version of R3 which read:"Each Transmission Owner shall have a documented transmission vegetation management program that describes how it conducts work on its Active Transmission Line ROWs to avoid Sustained Outages due to vegetation, considering all possible locations the conductor may occupy assuming operation within Rating and Rated Electrical Operating Conditions."However, if the SDT believes it is prudent to revise R3 in response to certain commenters, SCE would respectfully recommend R3 be revised to read:"Each Transmission Owner shall document the procedures, processes, or specifications it uses to prevent the encroachment of vegetation into the MVCD. Such documentation will account for the movement of transmission line conductors under their Rating and Rated Electrical Operating Conditions; and the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the Transmission Owner's applicable lines."
	Response: The SDT thanks you for your comment. The SDT agrees that the wording in R3 should be modified. R3 has been revised to remove the reference to "incorporate the dynamics" and has recrafted the requirement wording similar to your latter recommendation.		

	Organization	Yes or No	Question 4 Comment
9	CenterPoint Energy	No	See response to Q3 above. However, assuming R3 is not revised to exclude processes and procedures, we have no preference to the wording between the two drafts.
	Response: The SDT thanks you for your comment.		
10	Arizona Public Service Company	No	Still lacks detailed information. SDT needs to specify the documentation it is left up to interpretation by the utility.
	Response: The SDT thanks you for your comment. The SDT feels that the combination of the requirement wording and the examples and explanations in the Technical Reference Document are sufficient detail to portray the intent.		
11	MRO's NERC Standards Review Subcommittee (nsrs)	No	The NSRS does not believe that the new specificity that has been added to R3 will improve the reliability of the BES. It is our opinion that the requirement would have been clearer if it had ended after the first sentence. The additional language after the first sentence does not improve clarity. The whole (as written) requirement may be interpreted as a requirement for "each span" of Transmission line to which the Requirement will be applied. In measures for other requirements the SDT has done a very good job of stating and clarifying (in their opinion) what acceptable forms of evidence are. M3 would benefit from this type of clarification.
	Response: The SDT thanks you for your comment. The previous version of the Standard was crafted very much as you suggest. Many commenters disagreed with this approach, which led to the SDT to address this issue by adding the specificity. **R3 is a "competency based" requirement. The measure should be whether the methodology used by the TO to maintain vegetation passes the basic logic test. (eg: Our max growth rate is 3' per year. We have a minimum ground clearance spec for 230 kV of 24 feet at maximum sag. We maintain the lines every three years. During maintenance of 230 kV lines we remove all vegetation over 11.5 feet high) For a "results based" standard, the emphasis should be on the Tranmssion Owner demonstrating competency in its approach, however simple or complex that approach may be**		
12	NERC Staff	No	The removal of programmatic details from R3 renders the auditing task much more difficult. How does one assess the quality of the program except

	Organization	Yes or No	Question 4 Comment
			through the results required in R1 and R2? Since maintaining specific cut-to clearances is not required, there is much greater subjectivity in application that greatly complicates the auditor job. If the team does not want to limit the available approaches, it could provide flexibility by offering an array of deterministic formulas or approaches for maintaining vegetation. This might include maintaining vegetation to remain within a certain height from the ground given maximum sag distances. Additionally, this requirement does not seem to require the entity to actually follow its policies and procedures (unlike, for instance, R7). What is a violation here? Not having the documented procedure(s) OR whether the documented procedure(s) actually demonstrate that the entity can prevent encroachment? NERC staff is also concerned with some of the language in M3. Consider the following modification: "The Transmission Owner will have procedures, processes, or specifications as identified in Requirement R3, records showing work done to support its annual work plan identified in Requirement R7, and its quarterly vegetation reports, to demonstrate that it can prevent encroachment into the MVCD." Finally, with respect to the Rationale associated with R3, how would NERC enforce poor intent or a poor indication of competency (especially if the entity was performing well)? Recommend: Provide a basis for evaluating whether the Transmission Owner's procedures, processes, or specifications used to maintaining vegetation are achieving that goal. There may be many acceptable approaches to controlling vegetation so that it does not encroach into the MVCD. And one small copyedit: "interrelationships" should not have a hyphen.
	Response: The SDT thanks you for your comment.		

	Organization	Yes or No	Question 4 Comment
	Regarding the comments pertaining to the requirement wording: The intent of R3 in this version of the Standard is to make sure that the Transmission Owner adequately documents and demonstrates an understanding of the complex relationship of conductor movement under thermal and wind load and vegetation growing and moving in proximity to the line. The SDT points out that inclusion of a programatic list of activities by itself does nothing to to ensure reliability. R3 is a competency based requirement. The audit test is simply one of logic. Does the methodology the TO conveys in R3 logically ensure that no encroachments into the MVCD occur? The SDT feels that it is important for the Transmission Owner to have the flexiblity to choose how it satisfies this requirement and not to provide a limited menu of approaches that could be used. (eg: Our max growth rate is 3' per year. We have a minimum ground clearance spec for 230 kV of 24 feet at maximum sag. We maintain the lines every three years. During maintenance of 230 kV lines we remove all vegetation over 11.5 feet high) For a "results based" standard, the emphasis should be on the Tranmssion Owner demonstrating competency in its approach, however simple or complex that approach may be. The violation for this requirement would be either the TO failed to specify its approach or that the approach specified does not pass the logic test. **Regarding the comments pertaining to the measures M3: The SDT feels that an auditor knowledgeable of utility vegetation management work would be capable to evaluate if a well documented approach is sufficient to ensure no vegetation encroachments into the MVCD.** **Regarding the comments pertaining to the Rationale: The drafting team agrees that "intent" is not measurable or enforceable and has removed it from the rationale. The evaluation and measurement of the competency is listed above.**		
13	Consumers Energy Company	No	This really is another attempt at avoiding defining a minimum clearance specification and is not practical. As written, this would require each Transmission Owner to define and document the procedures, processes or specification by individual span for every line owned or operated by the Transmission Owner. Each span varies in length and profile and a single line may have several different conductor types with different load ratings. Line loadings will vary along the line based on substation taps, etc. The dynamics described in the language could only be done on an individual span basis to be reasonably accurate. This is not practical from a planning standpoint or from a standpoint of implementing clearing work in the field.
	Response: The SDT thanks you for your comment. The intent of R3 in this version of the Standard is to make sure that the Transmission Owner adequately documents and demonstrates that it understands the complex relationship of conductor movement under thermal and wind load and vegetation growing and moving in proximity to the line. It leaves the decision to the Transmission Owner how to satisfy this		

	Organization	Yes or No	Question 4 Comment
	"competency based" requirement. While a Transmission Owner could certainly take the approach that each individual span be addressed separately, it is also possible for a Transmission Owner to have a specific "vegetation maximum height" approach based on the minimum ground clearance specification of an entire line. Either extreme would satisfy this requirement. A Transmission Owner also could have an approach that contained a mixture of the two extremes.		
14	Allegheny Power	Yes	
15	Ameren	Yes	
16	American Transmission Company	Yes	
17	BGE Forestry Management	Yes	
18	Bonneville Power Administration	Yes	
19	Central Maine Power Company, Iberdrola USA	Yes	
20	Consolidated Edison Company of New York Inc	Yes	
21	FPL Corporate Compliance	Yes	
22	Duke Energy	Yes	
23	Entergy Services	Yes	

	Organization	Yes or No	Question 4 Comment
24	Exelon	Yes	
25	FirstEnergy	Yes	
26	Hydro One	Yes	
27	Idaho Power	Yes	
28	Idaho Power Company	Yes	
29	ITC Transmission	Yes	
30	Manitoba Hydro	Yes	
31	Northeast Power Coordinating Council	Yes	
32	Northeast Utilities	Yes	
33	Orange and Rockland Utilities, Inc.	Yes	
34	Pepco Holdings, Inc - Affiliates	Yes	
35	PNM	Yes	
36	Progress Energy	Yes	
37	South Carolina and Gas	Yes	
38	The United	Yes	

	Organization	Yes or No	Question 4 Comment
	Illuminating Company		
39	Tri-State Generation & Transmission	Yes	
40	Western Area Power Administration	Yes	
41	Western Electricity Coordinating Council	Yes	
	Response:		
42	Dominion	Yes	Although we agree with the intent of the proposed language, we feel the requirement should be revised to read:Each Transmission Owner shall document the procedures, processes, or specifications it uses to prevent the encroachment of vegetation into the MVCD. Such procedures, processes, or specifications shall consider the dynamics of a transmission line conductor's movement throughout its Rating and Rated Electrical Operating Conditions and the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the Transmission Owner's applicable lines.
	Response: The SDT thanks you for your comment. The SDT agrees that the wording in R3 should be modified. R3 has been revised to remove the reference to "incorporate the dynamics" and has recrafted the requirement wording similar to your latter recommendation.		
43	BC Hydro	Yes	As a competency requirement, R3 seems to be missing any requirement for a utility to define who is qualified to develop these plans, which is a departure from FAC-003-1 R1.3. I think that the utility should in their standards define who is qualified to develop their transmission vegetation management program
	Response: The SDT thanks you for your comment. While the SDT agrees that personnel qualifications are important in any pursuit for perfection, the overall approach for this version of the Standard is a "results based' product. In light of that, the SDT does not feel that a "fill in the blank" requirement for personnel		

	Organization	Yes or No	Question 4 Comment
	qualifications is necessary.		
44	Tampa Electric Company	Yes	This better clarifies section R3
	Response:		
45	Southern Company Transmission	Yes	While voting yes we are concerned about the interpretation of the expanded verbiage, how much documentation will be enough.
	Response: The SDT thanks you for your comment. The Technical Reference Document attempts to provide further explanation, along with examples, of how to present this information. While these examples are not in the Standard itself, the supplemental information in the Technical Reference Document should help the Transmission Owner understand the SDT's intent for the requirement, and therefore the documentation required to demonstrate competency.		

5. In response to comments received that requirement R7 is unclear with respect to flexible work plans, the SDT modified the requirement. Do you agree? Please explain.

Summary Consideration:

Of 45 respondents, there are 2 abstentions, 34 are in agreement, and 9 are in disagreement.

The major comment issues raised by those in disagreement are:

1. **The Requirement is vague and needs more specificity and explanation.**
   - **Does not require development of the Annual Vegetation Work Plan**
   - **Language allowing modifications to the Work Plan should specifically require documentation of changes**
   - **M7 is measuring completion of Work Plan, not prevention of encroachments into the MVCD**
   - **The phrase "…provided they do not put the transmission system at risk of a vegetation encroachment" could be better written as "…they do not allow encroachment of vegetation into the MVCD"**
2. **Examples describing potential reasons for plan modification should be clarified or eliminated.**
   - **Decreases in funding not valid.**
   - **Encroachments due to Major Storms are exempted in Footnote 2. R7 allows modification to Plan due to major storms but does not allow encroachments associated with plan change.**
   - **Generally. the examples identified are broad in nature**

Some minor comment issues are:

1. **Eliminate requirement or use the first sentence only.**
2. **Some concern with lack of agreement of language with other parts of the Standard.**

The VM SDT appreciated both the major and minor comment issues identified but decided that the requirement and measures are appropriate and clear as currently written and did not modify any of the language. The SDT reviewed the Funding Adjustment example for R7 and feels this is a valid reason for modifying the Annual Plan keeping in mind that a modification must not place the transmission system at risk of vegetation encroachment into the MVCD. In addition, as expressed in the Rationale, R7 sets the expectation that the work identified in the

annual work plan will be completed as planned. Documentation of the work completed (and any necessary modifications) as written together with the lack of a violation to either Requirement 1 or Requirement 2 is the overall reliability goal. The metric for the work plan is the percentage of the plan completed. The lack of a violation of R1 or R2 is the outcome of the ideal work plan. It is the responsibility of the Transmission Owner to manage the quality of the work plan and its associated modifications to mitigate the risk of a violation of R1 or R2. With Version 2, an outage is now clearly a violation of R1 and R2 and should not be linked to a failure of the work plan. The measure for the work plan is the percentage of the completed work as planned and we do not need to be subjectively trying to evaluate the quality of the Transmission Owner's work plan with this measure.

	Organization	Yes or No	Question 5 Comment
1	GDS Associates		
2	MWDSC (METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA)		
3	Western Area Power Administration	No	As the list of "examples of reasons for modification" is not all inclusive, it is unnecessary and could result in confusion regarding compliance when a scenario other than one listed requires a change. Further, documentation of changes to the annual plan adds unnecessary administrative burden which is inconsistent with a performance based standards approach.
	Response: Thank you for your response. The SDT feels the list of examples, while not all inclusive, is helpful to the TO in determining how and when to apply flexibility to its annual plan, when required. It is important the TO documents modefication to the plan to insure the work not completed during that period is carried over and completed within a reasonable time frame.		
4	Ameren	No	Funding Adjustments (increase or decrease) - need more description to imply only when planned vegetation work is "over and above".

	Organization	Yes or No	Question 5 Comment
	Response: Thank you for your comment. The SDT reviewed the Funding Adjustment example for R7 and feels this is a valid reason for modefying the Annual Plan keeping in mind that a modefication must not place the transmission system at risk of vegetation encroachement into the MVCD.		
5	MidAmerican Energy	No	MidAmerican supports the additional detail. However R7 should end after the first sentence. All additional material should be moved to the rationale box.
	Response: Thank you for your comment. The position of the SDT is to have this langiage in the requirement such to allow for flexibility to the work plan. Keep in mind Rationale language is clarifying documentation and not enforcable. The SDT feels it is important that the TO have the flexibility to revise its Annual Plan which is subject to many issues that can influence the completion of work.		
6	The United Illuminating Company	No	R1 and R2 are requirements that no encroachment occurs. R7, as proposed, requires a VMP to be completed to ensure no encroachment occurs. The Supplemental Reference for R7 does not describe the requirement of the annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. The Reference states the requirement is established to diminish the risk of encroachment; which is very different from ensuring no encroachment. In the Reference for R7 the word “ensure” is only used to describe that flexibility in the VMP is allowed to ensure the reliability of the Transmission System.M7 is measuring work plan completion not the prevention of encroachment. United Illuminating suggests that R7 be changed to: Each Transmission Owner shall complete the work in an annual vegetation work plan to manage the prevention of vegetation encroachments occur within the MVCD. In this way, a violation of R1/R2 does not necessarily mean R7 is violated. The entity does not avoid a penalty for an encroachment because a violation of R1/R2 occurs for actual encroachment. If an encroachment occurs the compliance enforcement authority can review the entities vegetation management plan to determine if it is compliance with R7/M7.
	Response: Thank you for your comments. As expressed in the Rationale, R7 sets the expectation that the work identified in the annual work plan will be completed as planned. Documentation of the work completed (and any necessary modifications) as written together with the lack of a violation to either Requirement 1 or Requirement 2 is the overall reliability goal. The metric for the work plan is the percentage of the plan completed. The lack of a violation of R1 or R2 is the outcome of the ideal work plan. It is the responsibility of		

	Organization	Yes or No	Question 5 Comment
	the Transmission Owner to manage the quality of the work plan and its associated modifications to mitigate the risk of a violation of R1 or R2. With Version 2, an outage is now clearly a violation of R1 and R2 and should not be linked to a failure of the work plan. The measure for the work plan is the percentage of the completed work as planned and we do not need to be subjectively trying to evaluate the quality of the Transmission Owner's work plan with this measure.		
7	CenterPoint Energy	No	See response to Q3 above.However, assuming R7 is not revised to exclude processes and procedures, the new wording is preferred since it is more specific. Additionally, a new ambiguous phrase is introduced, "provided they do not put the transmission system at risk of a vegetation encroachment", which we recommend to be changed to more specific wording, "provided they do not allow encroachment of vegetation into the MVCD".
	Response: Thank you for your comments. The SDT felt the language was appropriate.		
8	Southern Company Transmission	No	The first sentence of the Requirement 7 Rationale conflicts with the second sentence. The R7 Rationale should be reworded as follows:"This requirement sets the expectation that the work identified in the annual work plan should be completed as planned. However, an annual vegetation work plan must allow for work to be modified in response to changing conditions. These modifications must take into consideration the anticipated growth of vegetation and all other environmental factors, provided that the changes do not cause a vegetation encroachment within the MVCD."
	Response: Thank you for your comments. The SDT felt the language was appropriate.		
9	NERC Staff	No	This is the first instance in which an annual work plan is discussed. It would appear necessary to first develop an annual work plan component of the overall vegetation management program. There should also be some performance review or expectation that the annual plan as implemented achieved the intended program objectives, or that modifications would be necessary. Does R7 require both that a Transmission Owner has an annual vegetation

	Organization	Yes or No	Question 5 Comment
			work plan AND that it completes the work plan? Detail is required as to what is expected in the work plan, as there is currently no basis to judge whether the work plan is adequate or not adequate. And what does a modification entail? Does this mean reduction of performance, delay in performance, or complete postponement of performance? NERC staff is also concerned with the list of examples one might use to modify an annual plan. Several of these items should not pose any greater risk to vegetation contact and render the requirement virtually unenforceable. It provides a wide array of reasons to postpone vegetation management and may make it a very low priority for an entity: • “Rescheduling work between growing seasons”: This could be an honest change (if there are unexpected seasonal changes) or it could reflect bad initial planning. If there will be occasion for auditors and investigators to distinguish, there should be guidance on differentiating. • “Crew or contractor availability”: This could be an honest change (if there is an unexpected labor dispute or if crews are needed to help a neighboring utility during an unexpected emergency) or it could reflect bad initial planning. If there will be occasion for auditors and investigators to distinguish, there should be guidance on differentiating. Alternatively, it could be removed from the list as it is within the exclusive control of the Transmission Owner. • “Identified unanticipated high priority work”: This could be an honest change or it could reflect bad initial planning. If there will be occasion for auditors and investigators to distinguish, there should be guidance on differentiating. It is also vague and would necessitate a judgment call for enforcement. • “Permitting delays”: Annual plans should account for anticipated permitting schedules and maybe even add a factor for uncertainty. It is a planning issue for the entity and should not be an acceptable excuse for not conducting vegetation management. • “Land ownership changed”: If a landowner has the ability to affect the reliability of the bulk power system, the landowner should be subject to

	Organization	Yes or No	Question 5 Comment
			the reliability standards. A registered entity should be responsible for the land in its ROW, especially if it has turned control of the land, and the ability to affect reliability of the BPS, over to another entity or person for financial gain. • “Funding adjustments”: NERC staff is not convinced that this is a legitimate reason for adjusting an annual vegetation work plan. Economic considerations should not be a reason to delay or modify vegetation management. • “Emerging technologies”: It is unclear what this example is intended to accomplish. In general, these examples should be bounded in some way to ensure that a modification due to one of their occurrences does not impart a greater risk of vegetation contact.
	Response: Thank you for your comments. Per the SDT, developing the annual work plan is an understood requirement in order for the TO to complete the work plan. Thus, a requirement to develop the plan is not needed. R3 specifies the processes, procedures and/or specifications that are utilized by a TO to prevent an encroachment of the MVCD. This “Competency Based” requirement sets the core foundation that a TO will utilize to develop their annual work plan. **As expressed in the Rationale, R7 sets the expectation that the work identified in the annual work plan will be completed as planned. Documentation of the work completed (and any necessary modifications) as written together with the lack of a violation to either Requirement 1 or Requirement 2 is the overall reliability goal. The metric for the work plan is the percentage of the plan completed. The lack of a violation of R1 or R2 is the outcome of the ideal work plan. It is the responsibility of the Transmission Owner to manage the quality of the work plan and its associated modifications to mitigate the risk of a violation of R1 or R2. With Version 2, an outage is now clearly a violation of R1 and R2 and should not be linked to a failure of the work plan. The measure for the work plan is the percentage of the completed work as planned and we do not need to be subjectively trying to evaluate the quality of the Transmission Owner’s work plan with this measure.** **By bounding the flexibility as advocated, there are several variables involved such it makes it impractical to be able to address the many operational scenerios that a TO may experience. Thus, without being very prescriptive, the SDT feels that it is best to provide general guidance to what are valid modifications to the work plan.**		

	Organization	Yes or No	Question 5 Comment
10	Kansas City Power & Light	No	This requirement is in direct conflict with the “exclusions” as described in section 4.4. Section 4.4 makes it clear that effects of “major storms” on a vegetation programs efforts will be allowed as an exclusion toward compliance with these requirements, yet, R7 does not allow any encroachment due to modifications to a vegetation plans efforts due the “Major Storms” (second bullet) or “Weather conditions/Accessibility” (bullet 6). Please explain what is intended here that is different than what was intended in section 4.4.In addition, this presents some audit difficulties regarding the notion of detecting a “modified work plan”. Once a work plan is altered and new objectives are laid out, that becomes the plan and the plans that were replaced may be discarded since they would be of no value. Further, what difference does it make to track or monitor any changes to a work plan provided effective vegetation management is maintained? Recommend the SDT consider removing the language regarding “work plan flexibility” as this may suggest and impose an unnecessary compliance burden on Registered Entities and Auditors.
	Response: Thank you for your comments. The SDT views Major Storms in the list of examples differently than in Footnote 2. The example has more to do with schedules being revised as a result of a major storm while Footnote 2 refers to issues of sustained outages caused by circumstanses beyond the control of the Transmission Owner, and excepting resulting violations to the standard. **The SDT feels it is important to track and document changes in the work plan to insure rescheduled work is completed at some later date. Work plan flexibility through modification to the work plan is critical and must be recognized so that the Transmission Owner can propertly plan and revise work schedules when necessary.**		
11	Xcel Energy	No	What exactly does complete an annual work plan mean? It infers that an annual work plan must be developed/documented and executed. If this is the case, then clearly state as such.In general, R6 & R7 go against the grain of the results based standard concept. R1 already established that the Transmission Owner cannot have encroachment. R3 requires annual inspection (essentially establishing the plan). Why replicate in R6 & R7, it does not seem to serve any useful purpose.
	Response: Thank you for your comments. As stated in the Rationale, “This requirement sets the expectations that the work identified in the annual work plan will be completed as planned.” Because the		

	Organization	Yes or No	Question 5 Comment
	work plan is recurring in nature, a new work plan must be developed each year to state work planned for that period. This requirement directly supports Requirement 3 which calls for a documented vegetation management approach to prevent MVCD encroachments.		
12	Allegheny Power	Yes	
13	American Transmission Company	Yes	
14	Arizona Public Service Company	Yes	
15	BGE Forestry Management	Yes	
16	Bonneville Power Administration	Yes	
17	Central Maine Power Company, Iberdrola USA	Yes	
18	Consolidated Edison Company of New York Inc	Yes	
19	Consumers Energy Company	Yes	
20	FPL Corporate Compliance	Yes	
21	Dominion	Yes	

	Organization	Yes or No	Question 5 Comment
22	Duke Energy	Yes	
23	Entergy Services	Yes	
24	Exelon	Yes	
25	FirstEnergy	Yes	
26	Great River Energy	Yes	
27	Hydro One	Yes	
28	Idaho Power	Yes	
29	Idaho Power Company	Yes	
30	ITC Transmission	Yes	
31	Manitoba Hydro	Yes	
32	Northeast Power Coordinating Council	Yes	
33	Northeast Utilities	Yes	
34	Orange and Rockland Utilities, Inc.	Yes	
35	Pepco Holdings, Inc - Affiliates	Yes	
36	PNM	Yes	

	Organization	Yes or No	Question 5 Comment
37	PPL Electric Utilities	Yes	
38	Progress Energy	Yes	
39	South Carolina and Gas	Yes	
40	Tri-State Generation & Transmission	Yes	
41	Western Electricity Coordinating Council	Yes	annual vegetation management plans must have some flexibility. If the TO has the authority to create the plan they should have the authority to modify the plan. The key point is that changes, particularly delays to planned work would have to be approved. Do not believe “decreases in funding” should be listed as a valid reason for modification of work plan related to a reliability standard.From an enforcement viewpoint, there is ambiguity or perceived ambiguity in “provided they do not put the transmission system at risk of a vegetation encroachment.” Provided the potential that there may never be a self-report addressing this violation.
	Response: Thank you for your comments. The SDT agrees the plan needs flexibility and the Transmission Owner has authority for plan oversite. No approval for changes is called for in the requirement, but documentation is required to note the change. **The SDT reviewed the Funding Adjustment example for R7 and feels this is a valid reason for modifying the Annual Plan keeping in mind that a modification must not place the transmission system at risk of vegetation encroachment into the MVCD.**		
42	Southern California Edison Company	Yes	SCE agrees with the revisions to R7, but notes the some minor edits to the text are still needed.
	Response: Thank you for your comments. The SDT felt the language was appropriate.		
43	MRO’s NERC Standards Review Subcommittee (nsrs)	Yes	The NSRS has issue with the word “may” (and its components along with the associated bulleted points) and recommends that it is removed and placed in the rational box.

	Organization	Yes or No	Question 5 Comment
	Response: Thank you for your comments. The SDT believes the requirement as written is needed to insure flexibility of work plan.		
44	BC Hydro	Yes	The requirement as currently worded, seems to assume but does not explicitly state that a utility must prepare and document an annual vegetation work plan and document in some manner any modifications to that work plan as they occur. The work plan change documentation should include any risks of work deferral and mitigation plans to address those risks if there are any.
	Response: Thank you for your comments. Per the SDT, developing the annual work plan is an understood requirement in order for the TO to complete the work plan. Thus, a requirement to develop the plan is not needed. R3 specifies the processes, procedures and/or specifications that are utilized by a TO to prevent an encroachment of the MVCD. This "Competency Based" requirement sets the core foundation that a TO will utilize to develop their annual work plan. **The lack of a violation of R1 or R2 is the outcome of the ideal work plan. It is the responsibility of the TO to manage the quality of the work plan and mitigate any risk to the system associated with modifications to the work plan.**		
45	Tampa Electric Company	Yes	These changes add greater clarity, as well as real world examples, to this standard.
	Response: Thank you for your comments.		

6. In response to comments received that requirement R1/R2 may not adequately protect the transmission conductors under all conditions of sag and sway, the SDT drafted alternate language for the industry to provide feedback. The SDT did not opt to incorporate this language into "Draft 4" until further comment was solicited from industry. Which do you prefer? Please comment on your choice in the comment box below:

*"**Alternate R1/R2.** Each Transmission Owner shall manage the floor of its Active Transmission Line ROW in accordance to one of the following at all times:*

A) A fixed maximum vegetation height of 15 feet from the ground at the mid-half of the span and 20 feet in the outside quarters of the span, or,

B) A calculated maximum vegetation height that is the difference between the minimum conductor height at "max sag" minus MVCD minus cycle growth, or,

C) A calculated minimum vegetation to conductor clearance that is the sum of "max sag" in the span plus MVCD plus cycle growth, or,

D) A value determined by the Transmission Owner to provide a separation between the conductor and the vegetation that is comparable to options A, B, or C.

E) Any alternative approach that ensures no encroachment occurs within MVCD, considering the sag and sway of the conductor throughout its operating range under rated conditions.

F) A value to provide a separation between the conductor and the vegetation that is the sum of MVCD, and a value that considers the sag and sway of the conductor throughout its operating range under rated conditions plus 10 feet."

NOTE: The SDT suggests similar language as found in the posted draft for measures M1/M2 may be appropriate with this Alternate R1/R2.

Summary Consideration:

Of 45 respondents, there are 4 abstentions (expressed no preference for Draft or Alternate), 16 (two of which appear to be from the same company) are in agreement (that Alternate Language is preferred), and 25 are in disagreement (that Alternate is preferable, liking Draft language better).

The major comment issue raised is:

1. The only real issue raised in the comments by the 41 respondents that had a preference was that of the style of Requirement language appropriate for an RBS standard. Both groups agreed that either the Draft or Alternate language addressed the root requirement(s). In fact, respondents in both groups indicated that Option E

of the Alternate language was in essence the Draft language. (And of those in Alternate group that discussed the 6 options, E was the clear favorite, receiving five (5) mentions with A and C only receiving one (1).)

However, those that preferred the Alternate language cited that written in the form proposed by the Alternate language, the Requirements R1/R2 would provide much more flexibility and two respondents even cited that the Alternate allowed Transmission Owners to specify their own clearances.

For those voting for the Draft language (the majority), the most common reason cited was Draft language was less prescriptive. The second most common reason cited was that the Alternate Language would be confusing. And a couple commenters in this group opined that the Alternate language appeared to be “fill-in-the-blanks” language.

The VM SDT consideration for the major comment issue is:

1. Based on the “vote” the team will retain the Draft language. Also, Option E was cited most often by the Alternate group as the most desirable of the options and is in fact essentially the Draft language. The SDT was additionally swayed by the comments about confusion and fill-in-the-blanks as two overriding premises behind the standards should be clarity and acceptance by FERC.

A minor comment issue is:

1. Commenters offered several minor wording changes to the Draft language.

The VM SDT consideration for the minor comment issue is:

1. The team has incorporated some of these minor wording changes and rejected others when the change was found to introduce other problems.

	Organization	Yes or No	Question 6 Comment
1	MWDSC (METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA)		

	Organization	Yes or No	Question 6 Comment
2	Progress Energy		
3	South Carolina and Gas		
4	Arizona Public Service Company		Neither version is acceptable ANSI-A300 part 7 should be included here. Having set distances will give federal agencies the ability to minimize a utilities TVMP.
	Response: The SDT thanks you for your comments. The team appreciates your concern about federal agencies and other landowners' interpretation of the Requirement to impede vegetation management but is not swayed that the language currently in the Draft version suffers from a set distance specification as you cited.		
5	Bonneville Power Administration	Alternate version of R1/R2	
6	Central Maine Power Company, Iberdrola USA	Alternate version of R1/R2	
7	PNM	Alternate version of R1/R2	
8	GDS Associates	Alternate version of R1/R2	- E) seem more appropriate. The alternate R1/R2 standard requirements shall reduce the number of possibilities and simplify the criteria towards the design / operating conditions and additional standards ought to be considered in concert with current stan
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.		
9	Allegheny Power	Alternate version of R1/R2	Allegheny Power prefers the alternate version.
	The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which		

	Organization	Yes or No	Question 6 Comment
	may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.		
10	PPL Electric Utilities	Alternate version of R1/R2	Alternate C provides assurances that growth rates, maintenance cycle, and max-sag are taken into consideration.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft because the SDT believes it already addresses the provisions you state, i.e. growth rates, maintenance cycle, etc.		
11	Hydro One	Alternate version of R1/R2	Alternate Version E would allow a Transmission Owner to use an approach consistent with the current version of FAC-003 by defining a minimum clearance distance and a vegetation management clearance distance. This approach has met the objectives of FAC-003 since 2006. Use of version E would change the standard from a prescriptive approach to a Transmission Owner defined approach. In addition, Alternate Version E is preferred as it allows for variations based on differences in conductor heights, topography and other situations where a set height is not necessarily required in all instances and allows for the utility to determine the maximum heights of vegetation without performing detailed calculations of what the maximum heights must be along the various distances within each conductor span. If the utility is tasked with managing the vegetation to ensure no encroachments into the MVCD then it should be up to the individual utility how best to determine its management strategies that incorporate the determination of maximum vegetation heights in each section on its system.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.		
12	Northeast Power Coordinating	Alternate version of R1/R2	Alternate Version E would allow a Transmission Owner to use an approach consistent with the current version of FAC-003 by defining a

	Organization	Yes or No	Question 6 Comment
	Council		minimum clearance distance and a vegetation management clearance distance. This approach has met the objectives of FAC-003 since 2006. Use of version E would change the standard from a prescriptive approach to a Transmission Owner defined approach. In addition, Alternate Version E is preferred as it allows for variations based on differences in conductor heights, topography and other situations where a set height is not necessarily required in all instances and allows for the utility to determine the maximum heights of vegetation without performing detailed calculations of what the maximum heights must be along the various distances within each conductor span. If the utility is tasked with managing the vegetation to ensure no encroachments into the MVCD then it should be up to the individual utility how best to determine its management strategies that incorporate the determination of maximum vegetation heights in each section on its system.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.		
13	Idaho Power	Alternate version of R1/R2	Alternative R1/R2 allows the utility to maintain adequate clearances with their preferred approach.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.		
14	FirstEnergy	Alternate version of R1/R2	Although we agree with the alternate version of R1/R2, we have the following comments:1. We assume that R1 and R2 will be written similar to the current proposal with regard to IROL (High VRF) and non-IROL (Medium VRF) transmission lines, respectively. This should be clear after changes have been made to the standard before the final ballot.2. Although the SDT states that it "suggests similar language as found in the posted draft for measures M1/M2 may be appropriate with this alternate R1/R2", we are not clear how these measures will be written and would like to see a draft of the measures so we can review and

	Organization	Yes or No	Question 6 Comment
			comment.3. The alternate requirements appear to be "planning" in nature instead of "real-time"; we assume the intention of the SDT was the latter. Therefore the requirements should be revised with language that is "real-time" in nature.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.		
15	BGE Forestry Management	Alternate version of R1/R2	BGE believes R1/R2 should contain language that ensures that vegetation is manage taking into account sag and sway throughout the conductors operating range as the alternate language above outlines. The six options proposed allows the Transmission Owner the flexability needed to manage the active ROW a varity of ways and at the same time ensures the reliable operation the Bulk Electric System with respect to vegetation.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft because the SDT believes it already addresses the provisions you state, i.e. sag and sway.		
16	Idaho Power Company	Alternate version of R1/R2	I think this gives us more flexibility to maintain our clearances.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.		
17	Northeast Utilities	Alternate version of R1/R2	Option E above is preferred as it allows for variations based on differences in conductor heights, topography and other situations where a set height is not necessarily required in all instances and allows for the utility to determine the maximum heights of vegetation without

	Organization	Yes or No	Question 6 Comment
			performing detailed calculations of what the maximum heights must be along the various distances within each conductor span. If the utility is tasked with managing the vegetation to ensure no encroachments into the MVCD then it should be up to the individual utility how best to determine its management strategies that incorporate the determination of maximum vegetation heights in each section on its system.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.		
18	Consumers Energy Company	Alternate version of R1/R2	Prefer Alternative A
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.		
19	Kansas City Power & Light	Alternate version of R1/R2	Prefer Alternative E from the list above. Please clarify the meaning of sway in Alternative E. Is that wind blowout?
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft. Sway is synonymous with wind blowout in Alternative E. Please refer to the Technical Reference document for further clarification on this issue.		
20	Southern California Edison Company	Alternate version of R1/R2	SCE prefers the operational flexibility provided by the alternate version of R1/R2. We also note that dating back to development of FAC-003-1 and related comment periods, Transmission Owners have repeatedly stated that a "one-size-fits-all" TVMP is not viable or reasonable.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of		

	Organization	Yes or No	Question 6 Comment
	commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft. The SDT completely agrees with your comment about the 'one-size-fits-all' issue. The SDT has struggled with the proper wording that would allow each Transmission Owner the flexibility necessary to minimize the risk of vegetation outages while adapting to their unique vegetation challenges in a cost-effective-to-consumers manner. The SDT would encourage you, in future comment periods, to offer specific wording that will address the deficiencies you identified and what persuaded you to choose the Alternate version of R1/R2 as the preferred version.		
21	Ameren	Draft 4 version of R1/R2	
22	Duke Energy	Draft 4 version of R1/R2	
23	Exelon	Draft 4 version of R1/R2	
24	Great River Energy	Draft 4 version of R1/R2	
25	ITC Transmission	Draft 4 version of R1/R2	
26	MidAmerican Energy	Draft 4 version of R1/R2	
27	Pepco Holdings, Inc - Affiliates	Draft 4 version of R1/R2	
28	Tri-State Generation & Transmission	Draft 4 version of R1/R2	
29	Xcel Energy	Draft 4 version of R1/R2	Any of the alternate versions would amplify or create issues between land owners and Transmission Owners and are contrary to concepts of Integrated Vegetation Management, in particular, best management practices.
	Response: The SDT thanks you for your comments. Based on the industry support for the Draft 4 language, the SDT		

	Organization	Yes or No	Question 6 Comment
	has opted to retain the language in the current draft, in part because of the confusion you cited.		
30	American Transmission Company	Draft 4 version of R1/R2	ATC feels that Draft 4 Version of R1/R2 is the preferred version. The Alternate version is too prescriptive and has little flexability.
	Response: The SDT thanks you for your comments. Based on the industry support for the Draft 4 language, the SDT has opted to retain the language in the current draft; in part because of the prescriptive nature of the Alternate versions that you mentioned as well as it being noted as confusing.		
31	CenterPoint Energy	Draft 4 version of R1/R2	CenterPoint Energy does not believe a performance based requirement should be this prescriptive. However, if the majority of industry commenters agree with the SDT's approach, CenterPoint Energy has several concerns. The terminology, "operating within Rating and Rated Electrical Operating Conditions" is sufficiently definitive. There is no need to be more prescriptive. Alternate R1/R2 (E) is already similar to the Draft 4 wording. Of the two alternative, we recommend keeping the Draft 4 wording as is; however, we recommend moving the applicability of transmission line ratings to the Applicability section of the Standard as "4.5 Other: The Standard does not apply to any occurrence, non-occurrence, or other set of circumstances that are beyond the Rating and Rated Electrical Operating Conditions of the Facilities defined in 4.2." These conditions should be applicable to all elements and requirements of the Standard just as the force majeure statement does.
	Response: The SDT thanks you for your comments. Based on the industry support for the Draft 4 language, the SDT has opted to retain the language in the current draft, in part because of the prescriptive nature you mentioned as well as it being noted as confusing. The SDT has considered your excellent suggestion about the Applicability Section. However, after extensive discussion, the SDT opted not to add the language in the Applicability Section as the NERC framework for Applicability Sections seems to guide against it.		
32	Consolidated Edison Company of New York Inc	Draft 4 version of R1/R2	Consolidated Edison Company of New York, Inc prefers the Draft 4 version. The wording in the VSLs should be modified for both Requirements to include the phrase 'manage vegetation'. The phrase 'manage vegetation' requires a utility to take specific action to prevent encroachments/outages.

	Organization	Yes or No	Question 6 Comment
	Response: The SDT thanks you for your comments. The SDT has considered your excellent suggestion about the VSLs and decided to change the Requirements in the manner you describe.		
33	Entergy Services	Draft 4 version of R1/R2	Draft 4 is acceptable, but if alternate language is chosen, it should be similar to option E, keeping the determination simple and with as few variables for interpretation as necessary.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which could have simplified the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore the team has decided to retain the language in the current draft.		
34	Western Electricity Coordinating Council	Draft 4 version of R1/R2	Draft 4 should be sufficient. If industry believes MVCD is not adequate then the tables for MVCD should be modified to account for sag and sway.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which could have simplified the application by Transmission Owners but is concerned that a majority of commenters find the Alternate language confusing and potentially to be fill-in-the-blanks. Therefore the team has decided to retain the language in the current draft. The SDT is convinced that the technically defensible MVCD is adequate but appreciates the helpful suggestion nonetheless.		
35	Manitoba Hydro	Draft 4 version of R1/R2	I would suggest adding verbage to the draft 4 version to explicitly include the sag and sway of the conductor to the concept of "operating within rating and electrical operating condition"
	Response: The SDT thanks you for your comments. Based on the support for the Draft 4 language, the SDT has opted to retain the language in the current draft, in part because of the prescriptive nature you mentioned as well as it being noted as confusing. The SDT has considered your thoughtful and helpful suggestion about the explicit language which could be added to the Requirement to make it stand-alone and not rely on the Technical Reference document. The SDT, however, decided not to add the suggested verbiage because the team felt that the Rationale Box addressed this issue and the Requirement, if modified, would become somewhat confusing.		
36	MRO's NERC Standards Review	Draft 4 version of R1/R2	It is the NSRS's opinion that that the requirement as currently written in version 4 is consistent with the intent of a standard; i.e. stating what is

	Organization	Yes or No	Question 6 Comment
	Subcommittee (nsrs)		required as opposed to stating how to achieve what is required.
	Response: The SDT thanks you for your comments. Based on the support for the Draft 4 language, the SDT has opted to retain the language in the current draft, in part because of the prescriptive nature of the alternate that you cited, as well as it being noted as confusing.		
37	NERC Staff	Draft 4 version of R1/R2	NERC staff supports the Draft 4 version. The six options listed in the alternative version of R1/R2 do not seem manageable from a utility perspective. But while staff prefers the existing language, it continues to emphasize that fall-ins from outside the ROW can impact the line and need to be taken into consideration.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offered many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters, including you, find the alternate language confusing and some even cite that it may potentially be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current draft. Although the SDT understands that fall ins from off-ROW trees can negatively impact the lines and a sound TVMP would include a program to address these potential issues, it is not appropriate that off-ROW trees be included in a NERC Standard. This is mainly because a utility does not have the rights to remove private trees and the process to acquire rights to remove these trees is quite arduous and costly.		
38	Orange and Rockland Utilities, Inc.	Draft 4 version of R1/R2	Orange and Rockland Utilities, Inc prefers the Draft 4 version. The wording in the VSLs should be modified for both Requirements to include the phrase 'manage vegetation.' The phrase 'manage vegetation' requires a utility to take specific action to prevent encroachments/outages.
	Response: The SDT thanks you for your comments. The SDT has considered your excellent suggestion about the VSLs and decided to change the Requirements in the manner you describe.		
39	Tampa Electric Company	Draft 4 version of R1/R2	Quite frankly, the alternatives listed above, or for that matter any other vegetation managment options, should be establised by the utility. The goals in R1 & R2 are very clear. The alternatives listed above will create a double or triple standard of vegetation clearance for each different type of Transmission construction.

	Organization	Yes or No	Question 6 Comment
	Response: The SDT thanks you for your comments. Based on the support for the Draft 4 language, the SDT has opted to retain the language in the current draft, in part because of the confusion you mentioned.		
40	Dominion	Draft 4 version of R1/R2	The alternate language proposed above suggests that methodologies typically incorporated into processes, procedures, or specifications (as required by R3) should also be included into performance-based requirements R1 and R2. The incorporation of this language into R1 and R2 would change these requirements from performance-based requirements to hybrid performance/competency-based requirements.The intent of R1 and R2 is to define a failure to prevent encroachment into the MVCD. Ensuring that a TO's processes, procedures, or specifications demonstrate adequate means of protecting conductors falls under R3, which incorporates transmission conductor and vegetation dynamics and interrelationships. Therefore, methodologies employed to manage the floor of active transmission ROW should be incorporated into the documentation required by R3 and proof that vegetation was managed in accordance with processes, procedures, or specifications to prevent encroachment into the MVCD will be demonstrated by compliance with R1 and R2.
	Response: The SDT thanks you for your comments. Based on the support for the Draft 4 language, the SDT has opted to retain the language in the current draft, in part because it was less prescriptive and more performance-based as you mentioned.		
41	FPL Corporate Compliance	Draft 4 version of R1/R2	The alternative is a fill in the blanks requirement.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which could have simplified the application by Transmission Owners but is concerned that a majority of commenters find the Alternate language confusing and, as you cite, potentially to be fill-in-the-blanks.		
42	BC Hydro	Draft 4 version of R1/R2	The alternatives above are too prescriptive. A utility should set a preferred maintenance distance (i.e. clearance 1 in FAC-003-1) as routine expectation and outline mitigation strategies as required in areas where clearance 1 distances cannot be met to ensure that MVCD distances are not encroached upon. Given the various line design

	Organization	Yes or No	Question 6 Comment
			standards, it is the utility that must define those clearances and margins of error based on engineering standards and the types of vegetation and growth rates present in their operating area.
	Response: The SDT thanks you for your comments. Based on the support for the Draft 4 language, the SDT has opted to retain the language in the current draft, in part because it was less prescriptive as you cited.		
43	Western Area Power Administration	Draft 4 version of R1/R2	The current language of Draft 4 is the most flexible and offers industry the best opportunity for executing a cost effective and efficient program.
	Response: The SDT thanks you for your comments. The SDT has struggled with wording to try to allow each Transmission Owner the flexibility necessary to minimize the risk of vegetation outages while adapting to their unique vegetation challenges in a cost-effective-to-consumers manner. Based on the support for the Draft 4 language, the SDT has opted to retain the language in the current draft, because the SDT believes it achieves the goal you cited.		
44	The United Illuminating Company	Draft 4 version of R1/R2	UI prefers the draft language because we believe the intent of R1/R2 is to capture the actual occurrence of a vegetation related interruption or encroachment of vegetaion into the MVCD based on actual conditions.
	Response: The SDT thanks you for your comments. Based on the support for the Draft 4 language, the SDT has opted to retain the language in the current draft. As you describe, this language captures the true intent of the Requirements in the least confusing and prescriptive manner, as confirmed by other comments received.		
45	Southern Company Transmission	Draft 4 version of R1/R2	We feel the alternative language is too confusing. Does a utility choose one option from the list and expect it to cover all situations, or can the utility pick one option from the list and apply that option to one span, and then another option for the next span. The proposed alternate verbiage makes no distinction as to when options can or cannot be utilized. The language in Draft 4 seems to cover the various scenarios a utility will face in its vegetation management program while giving the utility the flexibility necessary to address these situations in an appropriate manner.
	Response: The SDT thanks you for your comments. Based on the support for the Draft 4 language, the SDT has		

	Organization	Yes or No	Question 6 Comment
	opted to retain the language in the current draft, in part because of the confusion you cited.		

7. The drafting team and NERC staff disagree on an appropriate set of VSLs for Requirements R1 and R2 and the Standards Committee has directed that both sets of VSLs be posted for stakeholder comments. Which set of proposed VSLs best supports NERC's VSL Criteria?

Summary Consideration:

Of 45 respondents, 6 chose neither set of VSLs, 8 disagreed with the SDT, and 31 agreed with the SDT.

Among those who disagreed with the SDT the major comment issues raised are:

1. **VSLs are too low and they do not seem to differentiate between various levels of compliance. Commenter is concerned that the difference between an encroachment that leads to an outage and one that does not is based on nothing but luck.**
2. **The NERC staff set requires a higher degree of accountability.**

The VM SDT considerations for the major comment issues are:

1. **The VM SDT proposed a set of four VSLs to reflect the wide range of non-compliances to these requirements. The NERC staff on the other hand view the outcomes as narrow.**

   The comment that SDT VSLs are "too low" lacks context. The commenter does not offer a frame of reference in rendering its opinion of "too low".

   The comment about luck is without basis. The SDT asserts that vegetation related outages are directly related to the encroachment mechanism, i.e., how vegetation contacts conductors.

   The differing perspectives do not appear to be reconcilable. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.
2. **The VM SDT believes the VSLs are precisely set to reflect the degree of accountability that best matches the level of non-compliance. Grow-in's are classified in the highest level of violation severity precisely because it is indicative of the lowest quality of performance and therefore the entity must be held to the highest degree of accountability in that case.**

Some minor comment issues are:

1. **Criteria will be probably best represented by a mix of the two VSLs.**

2. Neither set is correct.

The VM SDT considerations for the minor comment issues are:

1. The VM SDT proposed a set of four VSLs to reflect the wide range of non-compliances to these requirements. The NERC staff on the other hand view the outcomes as very narrow. The differing perspectives do not appear to be reconcilable through a hybrid approach as you suggested.

2. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.

	Organization	Yes or No	Question 7 Comment
1	MWDSC (METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA)		
2	Progress Energy		
3	Western Electricity Coordinating Council		
4	GDS Associates		Criteria will be probably best represented by a mix of the two VSLs as follows:- Keep the Lower and Moderate VSLs from SDT with both absent Sustained Outage. Add the fall-in as specific encroachment to the Lower VSL and grow-in as specific encroachment to the Moderate VSL- Keep the High / Severe VSLs from NERC
	Response: Thank you for your comment. The VM SDT proposed a set of four VSLs to reflect the wide range of non-compliances to these requirements. The NERC staff on the other hand view the outcomes as very narrow. The		

	Organization	Yes or No	Question 7 Comment
	differing perspectives do not appear to be reconcilable through a hybrid approach as you suggested.		
5	Pepco Holdings, Inc - Affiliates		Neither set is correct. The SDT proposed VSLs do not identify encroachment into the MVCD of a line not in an IROL or Major WECC transfer path, and the NERC Staff proposed VSLs do not do not identify encroachment into the MVCD of a line that is in an IROL or Major WECC transfer path
	Response: Thank you for your comment. Measures M1 & M2 along with The Rationale boxes for R1 & R2 can be used to understand what is meant by the MVCD. The Rational Box States: **"The MVCD is a calculated minimum distance stated in feet (meters) to prevent spark-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method."**		
6	CenterPoint Energy		Neither. However, we recommend that High or Severe violations be based only on Sustained Outages experienced and the reliability importance of the transmission line. Any process or procedure based requirement, if kept within the Standard, should have a Lower or Moderate designation based on the utilities intent or capability to comply with the Requirement.
	Response: Thank you for your comment. The VM SDT proposed a set of four VSLs to reflect the wide range of non-compliances to these requirements. The NERC staff on the other hand view the outcomes as very narrow. The differing perspectives do not appear to be reconcilable. Your suggestion is appreciated, however the VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
7	Consumers Energy Company	VSLs proposed by NERC staff	
8	Idaho Power Company	VSLs proposed by NERC staff	
9	FPL Corporate Compliance	VSLs proposed by NERC staff	Again the drafting team is trying to control the terms of a requirement by using the compliance elements. FPL agrees there is a direct link between vegetation growing in to conductors from below has a direct correlation to cascading events and fall-in and blow-in outages are no

	Organization	Yes or No	Question 7 Comment
			more incidental than a cross arm failure to a cascading event. These components should be handled in the requirements and not in the compliance element.
	Response: Thank you for your comment. The VM SDT proposed a set of four VSLs to reflect the wide range of non-compliances to these requirements. The NERC staff on the other hand view the outcomes as very narrow. The differing perspectives do not appear to be reconcilable. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
10	Dominion	VSLs proposed by NERC staff	As all parts of R1/R2 seem to contribute equally to the intent of the requirement - shall manage vegetation to prevent encroachment that could result in a Sustained Outage - NERC's proposed VSLs best address noncompliance with the requirements.
	Response: Thank you for your comment. The VM SDT proposed a set of four VSLs to reflect the wide range of non-compliances to these requirements. The NERC staff on the other hand view the outcomes as very narrow. The differing perspectives do not appear to be reconcilable. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
11	NERC Staff	VSLs proposed by NERC staff	NERC staff supports the VSLs proposed by NERC staff. The SDT's VSLs are too low, and they do not seem to differentiate between various levels of compliance. Still, staff is concerned that the difference between an encroachment that leads to an outage and one that does not is based on nothing but luck.
	Response: Thank you for your comment. The VM SDT proposed a set of four VSLs to reflect the wide range of non-compliances to these requirements. The NERC staff on the other hand view the outcomes as very narrow. **The comment that SDT VSLs are "too low" lacks context. The commenter does not offer a frame of reference in rendering its opinion of "too low".** **The comment about luck is without basis. The MVCD distances are conservative and it is quite possible to be well within the MVCD and not have a flashover or an outage. This is based on physics, not "luck". Prudent inspection frequencies and a good imminent threat notification process are 2 things that could prevent encroachments from becoming an outage. Stating that it is only dependent on luck does not give proper credit to prudent operations.** **The SDT has revised R1 and R2 to clarify that the level of maintenance is the primary focus of this requirement that must be attained to be compliant. The VM SDT feels these changes will ensure congruence between the requirements**		

	Organization	Yes or No	Question 7 Comment
	and the VSL.		
12	Arizona Public Service Company	VSLs proposed by NERC staff	Requires a higher degree of accountability as it should be.
	Response: Thank you for your comment. The VM SDT proposed a set of four VSLs to reflect the wide range of non-compliances to these requirements. The VM SDT believes the VSLs are precisely set to reflect the degree of accountability that best matches the level of non-compliance. A grow-in is classified in the highest level of violation severity precisely because it is indicative of the lowest quality of performance. Therefore, the entity must be held to the highest degree of accountability for any maintenance failure that leads to a grow-in. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
13	Idaho Power	VSLs proposed by NERC staff	Seems like there should be a lesser severity level for violations for R3-R7.
	Response: Thank you for your comment. This question asks for feedback on the VSLs assigned to R1 and R2.		
14	The United Illuminating Company	VSLs proposed by NERC staff	United Illuminating agrees with NERC Staff that the Requirement is to prevent encroachment of any kind. Differentiating between fall-in and grow-in is of no consequence to the intent of the requirement.
	Response: Thank you for your comment. Please refer to the SDT response to NERC on this question.		
15	Allegheny Power	VSLs proposed by the VM SDT	
16	Ameren	VSLs proposed by the VM SDT	
17	BGE Forestry Management	VSLs proposed by the VM SDT	
18	Bonneville Power Administration	VSLs proposed by the VM SDT	
19	Duke Energy	VSLs proposed by the VM SDT	

	Organization	Yes or No	Question 7 Comment
20	Exelon	VSLs proposed by the VM SDT	
21	ITC Transmission	VSLs proposed by the VM SDT	
22	Manitoba Hydro	VSLs proposed by the VM SDT	
23	MidAmerican Energy	VSLs proposed by the VM SDT	
24	MRO's NERC Standards Review Subcommittee (nsrs)	VSLs proposed by the VM SDT	
25	Northeast Utilities	VSLs proposed by the VM SDT	
26	PPL Electric Utilities	VSLs proposed by the VM SDT	
27	South Carolina and Gas	VSLs proposed by the VM SDT	
28	Tri-State Generation & Transmission	VSLs proposed by the VM SDT	
29	Xcel Energy	VSLs proposed by the VM SDT	
30	Central Maine Power Company, Iberdrola USA	VSLs proposed by the VM SDT	Agrees with SDT that violation risk factors must be ranked in accordance with impact on the bulk delivery system.
	Response: Thank you for your comment.		

	Organization	Yes or No	Question 7 Comment
31	Kansas City Power & Light	VSLs proposed by the VM SDT	Although the Drafting Team is favored here, it makes little sense in the NERC Staff VSL to have an encroachment with no sustained outage as a HIGH VSL. No compromise of the real-time reliability of the bulk electric system occurred. How could that be a HIGH? If it is determined to use the VSLs proposed by NERC Staff, it is recommended to change the HIGH VSL to LOWER.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
32	American Transmission Company	VSLs proposed by the VM SDT	ATC believes the VSLs proposed by the VM SDT best supports the NERC's VSL Criteria. The NERC Staff VSLs do not allow for Lower or Moderate VSLs which recognizes significant value as nearly meeting the intent of the requirement. Furthermore, it does not allow for encroachment where absent a sustained outage. Every encroachment in real time would not go directly to a "High" VSL where performance has limited value.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
33	FirstEnergy	VSLs proposed by the VM SDT	FE supports the VSL proposed by the SDT. We believe these have been developed in accordance with the FERC approved VSL guidelines and represent the appropriate violation levels for situations of varying probabilities. History has proven the grow-ins are the biggest cause of vegetation contact issues, and fall-ins and blowing together vegetation are very hard to predict and control and should be at lower violation levels. Although we believe that an encroachment into the MVCD that causes no system disturbance should not be penalized if an entity takes immediate action to restore the minimum clearance, the assignment of a Lower VSL is appropriate. We believe that the NERC staff opinion that this situation warrants a High VSL does not demonstrate thorough rationalization because it fails to consider the consequences that would place a severe monetary penalty on an entity for a situation that did not cause a fault, outage, or cascade of the BES.Furthermore, it is clear

	Organization	Yes or No	Question 7 Comment
			from the bullet points under R1 and R2 of the proposed standard language that the SDT intended that an encroachment with a sustained outage is different than and encroachment without a sustained outage otherwise they would not have specified the bulleted situations in detail. Had the SDT intended for there to be only two violation severity levels they would have only specified two bullet items: an encroachment with a sustained outage and an encroachment without a sustained outage. The requirements are the only tools the drafting team has to specify its intent in this area and the approach they used is reasonable to provide these levels of differentiation.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
34	Great River Energy	VSLs proposed by the VM SDT	GRE prefers the Drafting Team's VSLs over the VSLs written by the NERC staff. The VSLs that were written by the SDT appear to be clearer and less subjective as opposed to the VSLs that were written by NERC staff. The VSLs written by the NERC staff came across as being less clear and more subjective.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
35	Southern California Edison Company	VSLs proposed by the VM SDT	SCE agrees with the SDT's rationale and proposals for VSL Criteria.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
36	Tampa Electric Company	VSLs proposed by the VM SDT	Tampa Electric agrees with the SDT statement ... "For example, not all encroachments lead to Sustained Outages." As such, we agree, a lower level of VSL is appropriate. Tampa Electric also agrees with this statement " Moreover, there is an operational differentiation between a fall-in, blow-together or grow-in event. "Recommend the

	Organization	Yes or No	Question 7 Comment
			team examine the analytical rational for the following statements so as to better explain and clarify this issue to NERC. "A fall-in has never been known to cause a cascading outage. Therefore the team feels that a Lower VSL is appropriate. A blowing-together-caused fault is somewhat more egregious than a fall-in, as it has the potential for re-occurring and is therefore assigned a Higher VSL."
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
37	PNM	VSLs proposed by the VM SDT	The expectation is for perfection or zero encroachments at all times. It would be cost prohibitive to maintain the system under those rules. PNM recommends the VM SDT VSL's.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
38	BC Hydro	VSLs proposed by the VM SDT	The NERC staff recommendation is too restrictive and does not seem realistic in an operational sense. We do not agree that the standard should apply to outages from vegetation falling into the conductor from within the active transmission right of way. This normally would not occur except during storm events that would be excluded from this standard. It is operationally difficult to know precisely where the edge of the right of way is in all situations and under all conditions. Further, in clearing some sections to this degree, the utility could end up destabilizing what is currently a stable, windfirm edge and pose higher security risks to the transmission system from destabilizing the vegetation through excessive clearing. So this gets down to semantics of how a utility might define their active right of way corridor relative to the legal statutory right of way edge. The risk of fall into outages needs to be managed but as currently defined this is too absolute a requirement. Fall-into outage risks need to be mitigated but they have not been a key element of any cascading failure and are hard to prevent. Even if a right of way were cleared sufficiently wide to avoid a fall-into outage, there is always a risk of branches being blown into the conductors from sailing during higher winds (e.g. Douglas-fir branches have excellent airborne gliding

	Organization	Yes or No	Question 7 Comment
			abilities). The greatest risk is from grow-into outages or from conductors and vegetation being blown into one another within the active right of way. Therefore, we prefer the VSLs set by the VM standard development team.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
39	Consolidated Edison Company of New York Inc	VSLs proposed by the VM SDT	The wording in the VM STD VSLs should be modified to include whether or not the TO managed any vegetation on that particular line. A more severe VSL should be assigned to any encroachment or sustained outage that was caused as a result of a TO not performing any vegetation management activities on that line. For example, if vegetation management activities were completed on 80% or 90% of the line and additional work was in progress on the remainder of the line but an encroachement or sustained outage occurred on the spans that were scheduled to be done as part of the annual plan, the TO should be held accountable for this but at a lower severity level.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
40	Hydro One	VSLs proposed by the VM SDT	The wording in the VM STD VSLs should be modified to include whether or not the TO managed any vegetation on that particular line. A more severe VSL should be assigned to any encroachment or sustained outage that was caused as a result of a TO not performing any vegetation management activities on that line. For example, if vegetation management activities were completed on 80% or 90% of the line and additional work was in progress on the remainder of the line, but an encroachment or sustained outage occurred on the spans that were scheduled to be done as part of the annual plan, the TO should be held accountable for this but at a lower severity level.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		

	Organization	Yes or No	Question 7 Comment
41	Northeast Power Coordinating Council	VSLs proposed by the VM SDT	The wording in the VM STD VSLs should be modified to include whether or not the TO managed any vegetation on that particular line. A more severe VSL should be assigned to any encroachment or sustained outage that was caused as a result of a TO not performing any vegetation management activities on that line. For example, if vegetation management activities were completed on 80% or 90% of the line and additional work was in progress on the remainder of the line, but an encroachment or sustained outage occurred on the spans that were scheduled to be done as part of the annual plan, the TO should be held accountable for this but at a lower severity level.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
42	Orange and Rockland Utilities, Inc.	VSLs proposed by the VM SDT	The wording in the VM STD VSLs should be modified to include whether or not the TO managed any vegetation on that particular line. A more severe VSL should be assigned to any encroachment or sustained outage that was caused as a result of a TO not performing any vegetation management activities on that line. For example, if vegetation management activities were completed on 80% or 90% of the line and additional work was in progress on the remainder of the line but an encroachement or sustained outage occurred on the spans that were scheduled to be done as part of the annual plan, the TO should be held accountable for this but at a lower severity level.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
43	Entergy Services	VSLs proposed by the VM SDT	This gives the option to activate and follow the Imminent Threat Process if a breach of the MVCD is located and reported for isolated events absent a sustained outage. It gives the TO the opportunity to mitigate the issue when it is identified and corrected prior to experiencing an outage..
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		

	Organization	Yes or No	Question 7 Comment
44	Western Area Power Administration	VSLs proposed by the VM SDT	Unlike a “grow-in”, a “fall-in” or “blow-in” has never caused or contributed to a cascading outage. Further, the “zero tolerance” approach of this standard remains impractical and unreasonable. The gradated indicators of program performance associated with a “fall-in”, “blow-in” and “grow-in” offer some measure of reasonableness to the requirement.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
45	Southern Company Transmission	VSLs proposed by the VM SDT	We support the SDT version of the VSLs. The version proposed by staff does not recognize the objective of FAC-003-2 which clearly states, “To improve the reliability of the electric Transmission system by preventing those outages that could lead to Cascading.” If a fall-in occurs in an afternoon thunder storm and investigation reveals the tree was on the right-of-way by one or two feet, staffs VSLs would treat this outage with the same severity as an outage where a fully loaded line in a heat wave sagged into unmaintained brush growing directly beneath the conductor. The first case would rarely, if ever, lead to cascading. The second case could easily lead to cascading. Staff’s VSLs seem to indicate a desire to “gold plate’ the system to insure 100% reliability, which will never be achieved absent of unlimited resources and with total disregard to cost.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		

8. Is there anything that you have not addressed above regarding the draft FAC-003-2 Transmission Vegetation Management standard or the Technical Reference Document? If yes, please provide what you believe should be changed, added or deleted and the rationale for your proposal.

Summary Consideration:

Of the 45 respondents, 29 provided a comment. In general, there were no common themes and as such each comment was responded to individually. Of some note, two comments were especially lengthy and their well-considered responses are found below.

	Organization	Yes or No	Question 8 Comment
1	Great River Energy		
2	Allegheny Power	No	
3	Central Maine Power Company, Iberdrola USA	No	
4	Consumers Energy Company	No	
5	Duke Energy	No	
6	Exelon	No	
7	Manitoba Hydro	No	
8	Northeast Utilities	No	
9	Pepco Holdings, Inc - Affiliates	No	
10	PNM	No	

	Organization	Yes or No	Question 8 Comment
11	PPL Electric Utilities	No	
12	South Carolina and Gas	No	
13	Tri-State Generation & Transmission	No	
14	Western Area Power Administration	No	
15	Western Electricity Coordinating Council	No	
16	Tampa Electric Company	No	No additional comments
17	GDS Associates	Yes	- Effective Dates. Clarify effective dates in paragraphs 2 and 3. This should only be applicable to Canada as Standard are not mandatory and enforceable in the US unless further approved by FERC.- Exceptions. Regional Differences must be approved just li
	Response: The SDT thanks you for your response. NERC staff will review the effective date section and modify as necessary.		
18	Progress Energy	Yes	1) On p. 3 of the redline, the table of Effective Dates is struck out, but the key (listed as 1, 2, 3 below the table: “1. First calendar day...”) remains but now the numbers 1, 2, and 3 no longer refer to the table of Effective Dates as the table has been struck. 2) The first paragraph under “Exceptions” could be reworded to be clearer. As currently proposed, it states lines below 200kV become subject to the standard 12 months after the lines are designated as being subject to the standard, which is somewhat circular. We propose instead:”A line operated below 200kV becomes subject to this standard 12 months after the date the Planning Coordinator or WECC initially designates the line as an element of an IROL or as a Major WECC transfer path.”3)

	Organization	Yes or No	Question 8 Comment
			Applicability Section 4.2.4 says the standard does not apply to Facilities located in the fenced area of a switchyard. However, p. 8 in Section 5 Background says the standard does not apply to underground or submarine lines or line sections inside a station boundary. Two things should be addressed to make these consistent: "Facilities" is a NERC-defined term that includes more than just lines, and includes lines, generators, compensators, transformers, etc. Also, is the "station boundary" always defined by the fenced area? Any potential conflict due to this inconsistency should be resolved.4) In the redline of Draft 4, in R5 and M5, the word "interim" is struck through. However, the Rationale box says "....the intent is for the Transmission Owner to put interim measures in place..." The use of "interim" should be consistent between R5, M5 and the Rationale box.5) R6 requires the TO to perform Vegetation Inspections "at least once per calendar year". There could potentially be future interpretation requests that question whether "once per calendar year" means performance sometime during each year (i.e. 2010, 2011, etc.), or whether no more than 365 calendar days can elapse between inspections. The first interpretation could allow up to almost 2 years to elapse between inspections even when doing it "once per calendar year". This should be clarified.
	Response: The SDT thanks you for your response. NERC staff will review the effective date section and modify as necessary. Thank you for the wording, but overall industry consensus does not dictate a verbiage change. **Regarding station boundaries and underground lines, overall industry consensus is that line-based vegetation programs do not apply inside the station boundary. The SDT believes that "fence" is the best overall term for a station boundary.** **As to the use of "interim", the Rationale intends to provide clarifying text and there is no imperative that its language should be identical to the requirement verbiage. The SDT believes that the Rationale language properly conveys the intent.** **Regarding the inspection frequency, the SDT added an 18 month clause.**		
19	CenterPoint Energy	Yes	1. CenterPoint Energy believes the proposed FAC-003-2 is not a performance-based standard, despite being labeled as such, because it remains too focused on processes and procedures. CenterPoint Energy fails to see much difference in the approach from the current Standard.

	Organization	Yes or No	Question 8 Comment
			CenterPoint Energy believes a performance based requirement would provide performance criteria that an entity would be measured against. An example of a performance based requirement would be the following: R1. "Each Transmission Owner shall manage vegetation to prevent encroachment that results in no more than one (1) Sustained Outage per XXX circuit miles of applicable lines within any twelve (12) month period." M1. Each Transmission Owner has evidence that it had in no more than one (1) Sustained Outage per XXX circuit miles of applicable lines within any twelve (12) month period. Examples of acceptable forms of evidence may include dated reports of vegetation-related Sustained Outages or dated attestations as to no vegetation-related Sustained Outages have occurred. However, if the majority of industry commenters agree with the SDT's approach, CenterPoint Energy has the following additional concerns: 2. The phrases "active transmission line ROW" and "Active Transmission Line ROW" are no longer considered defined terms and should be deleted from the Standard along with footnote 2, the Compliance Section for Periodic Data Submittal as well as the Guidelines and Technical Basis. As found throughout the Standard, the phrase should be replaced with the common terms utilized in the Guidelines and Technical Basis section, "Transmission Owner's transmission ROW as defined by easement, fee simple, or other legal rights". 3. In the Background section fall-ins are characterized as "statistically intermittent" and "these types of events are highly unlikely to cause large-scale grid failures". We agree and therefore recommend that fall-ins be excluded from the Requirements R1, R2, and Periodic Data Submittal of outages. 4. R4 should be deleted. R4 is related to processes and procedures and should be combined into R3. The result of not following the notification process or procedure is that a Sustained Outage may occur that would be

	Organization	Yes or No	Question 8 Comment
			captured by M1 and M2. The process and procedure would be measured by M3. 5. R5 and M5 contain the ambiguous phrase, "where a transmission line is put at risk due to the constraint". This phrase should be replaced with the more specific terminology in R1 and R2 as, "where a transmission line cannot perform within its Rating and Rated Electrical Operating Conditions due to the constraint" or as in R3 as "where a transmission line will be subjected to an encroachment into the MVCD due to the constraint". 6. For R6, the detailed rationale and studies used for the determination of the required one year inspection cycle should be included in the Guidelines and Technical Basis. The explanation provided in the Rationale that it is "based upon average growth rates across North America and on common utility practice" are unfounded and arbitrary without a specific reference to a North American study. 7. R7 contains the ambiguous phrase, "provided they do not put the transmission system at risk of a vegetation encroachment". This phrase should be replaced with the more specific terminology in the Rationale for R7 and Requirement R3 as "provided they do not allow encroachment of vegetation into the MVCD." 8. Just as the force majeure statement was moved to the Applicability section of the Standard, the exception for applicability beyond the Rating and Rated Electrical Operating Conditions should be included in the Applicability section as well. Currently, it is only included in R1, R2, and R3. It should be made clear that the other Requirements and Measurements ARE NOT applicable in situations beyond the Rating and Rated Electrical Operating Conditions. This is already discussed in the Guidelines and Technical Basis but not evident within the Standard. 9. The Periodic Data Submittal should be clarified to as to the specific conditions under which Sustained Outages are reported. The Applicability section includes the force majeure; however, other exclusions are not so evident. We recommend the wording be changed to include all applicable

	Organization	Yes or No	Question 8 Comment
			exclusions for added clarity. We recommend the following wording: "The Transmission Owner will submit a quarterly report to its Regional Entity, or Regional Entity's designee, identifying the Sustained Outages caused by vegetation, as defined in the categories below, of transmission lines operating within Rating and Rated Operating Conditions as determined by the Transmission Owner, exclusive of the force majeure conditions in Section 4.4, that include, as a minimum, the following." Also, the within the Categories listed, the phrases "active transmission line ROW" should be deleted and replaced with "Transmission Owner's transmission ROW as defined by easement, fee simple, or other legal rights". This places the determination of the width of the ROW for determination of fall-in violations clearly on the Transmission Owner and the within the limits of its legal rights to control the vegetation that has fallen into the line under R1 and R2 causing the submittal of a reportable sustained outage. 10. The Guidelines and Technical Basis and the Technical Reference with the Gallet Equation should be combined into one document as a supplement to the Standard to avoid duplication in wording and misinterpretation of context. 11. We agree that the Rationale test boxes should be deleted from the Standard and applicable explanatory text be included within the Guidelines and Technical Basis. 12. The Guidelines and Technical Basis should include the background and basis for 4.2.4 that excludes the Standard from applying to fenced substations. 13. The Guidelines and Technical Basis should contain more specific examples of violations of the Requirements and highlight specific exceptions related to vegetation related outages, especially fall-ins and force majeure exclusions. 14. The language in R6 refers to inspecting "transmission lines" and Table 1 for

	Organization	Yes or No	Question 8 Comment
			R6 refers to inspecting “ROW”. Both areas should use consistent terminology. 15. In the Guidelines and Technical Basis section for R6, the reference to the VSL calculation units and the example units should be consistent-the example should use “circuit miles”, not just “miles”. 16. In general, the proposed FAC-003-2 has gone FAR beyond what was contemplated by the Commission in FERC Order 693 and equates to a total re-writing of the Standard for no apparent reason. The Commission's determination dealt with the following areas: (1) applicability; (2) inspection cycles; and (3) minimum clearances on National Forest Service lands. For instance in Paragraph 729, the Commission states, “As proposed in the NOPR, the Commission approves Reliability Standard FAC-003-1 with no proposed modification on the issue of clearances. The Commission reaffirms its interpretation that FAC-003-1 requires sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions....” Rewriting the minimum clearances introduced a new set of confusing definitions, and further burdens the Transmission Owners with new documentation requirements with little if any benefit when compared to the Clearance 2 concept in the existing Standard. A preferred approach should be to incorporate the following few items into the existing Standard FAC-003-1: (1) the RC versus the RRO; (2) the designation of a specific inspection frequency; (3) the Gallet equation; and

	Organization	Yes or No	Question 8 Comment
			(4) the applicability to National Forest Service lands.
	Response: 1) The SDT thanks you for your responses. The standard is intended to be a Results-based standard and includes requirements that are risk-based, competency-based and performance-based. The SDT and NERC staff feels that it represents a significant departure from previous versions. The SDT has considered “per-mile”-based metrics, but believes that FERC will not approve such a metric due to statutory constraints and its stated criteria for approval of a standard. 2) Based on your comment and others, the SDT has revised the definition of ROW in the NERC Glossary and removed Table 3. 3) While the SDT agrees that fall-ins are statistically intermittent, the fall-ins from inside the ROW are under the control of the TO and represent an erosion of reliability. 4) The SDT agrees that there is some logic in your proposal, but the SDT feels that all TOs should have a procedure that results in a defense-in-depth strategy as is in the current draft. 5) R5 applies in the longer-term Operations Planning time horizon, whereas R1 and R2 apply in real time. On the other hand, R3 is a competency-type of requirement that applies in the Long-Term Planning Time Horizon. 6) The SDT posed the question of inspection frequency to the overall industry in an earlier posting and received general consensus that a one-year interval would be appropriate but did add an 18 month clause. 7) R7 addresses shorter-term risks, whereas the language in R3 is about the prevention of encroachments in the wider long-term horizon. 8) The SDT has considered your suggestion about the applicability section; however, after extensive consideration, the SDT opted not to add the language you suggested since the NERC framework for the Applicability section guides against it. 9) Thank you. The SDT agrees and hereby adds “. . . except as excluded in Footnote 2” before “that includes.” Regarding your suggestion on active TLROW, the SDT changed the definition of ROW in the NERC Glossary. 10) The issue of combining these documents will be addressed by NERC as the results-based standard-		

	Organization	Yes or No	Question 8 Comment
	making procedural document is finalized. **11) The final resolution of this issue will be addressed by NERC as the results-based standard-making procedural document is finalized.** **12) The SDT believes that industry generally supports the exclusion of substations from applicability of the standard, and does not believe that every clause or portion of the Standard needs an explanation in the *Guidelines and Technical Basis*.** **13) The team does not feel that extensive examples, especially of violations, have a place in the Standard.** **14) You have pointed out a conflict in nomenclature between two portions of the standard. The team will resolve the conflict.** **15) As mentioned in both M6 and the VSL table for R6, the TO may choose its unit of measure.** **16) The SDT considered the SAR and FERC Order 693 directives together with the imperative that reliability not suffer with the revised standard, and feels that it has improved the Standard accordingly.**		
20	Kansas City Power & Light	Yes	1. Part R4.3, "Enforcement, under Section 4, "Applicability", is confusing as to why it is needed. What is the intended purpose of this part? It is clear that each Requirement, Measure, VRF and VSL when adopted by the NERC BOT and FERC become mandatory and enforceable on the declared effective date(s). There is no need for Part R4.3 to reinforce the compliance enforcement dictated by the established NERC Rules of Procedure.2. Requirement R4: The requirement is clear to notify the appropriate control center regarding conditions that might cause a fault on a transmission facility. The requirement should be clear, this for the Transmission Owners applicable lines and recommend the SDT modify the language in R4 to that end. In addition, there is no action other than notification in regards to this operating condition. Highly recommend the SDT consider adding language to take "immediate actions" to remedy the vegetation condition and remove the threat.3. Requirements R5 & R7 are not clear in that they are for the Transmission Owners applicable lines. This has been a common theme throughout this Standard and by the omission of this language, it is not clear that the intended scope of the requirements do not go beyond the applicable lines.
	Response:		

	Organization	Yes or No	Question 8 Comment
	1. Thank you for your comment. NERC staff will address this concern. **2. The SDT feels that the applicability of lines is sufficiently clear in R4. However, it is not appropriate for this Standard to specify any particular action for the TOP to take; this is the realm of TOP-006.** **3. The SDT feels that the applicability of lines is sufficiently clear in R5 and R6.**		
21	American Transmission Company	Yes	1.) Rationale boxes associated with R1, R2 and R3 within the standard include reference Tables and Figures in the “Guidelines and Technical Basis” without specifying where they are located. ATC recommends inserting this information as applicable.2.) ATC raises a previous draft concern on including Rationale Boxes plus Guidelines and Technical Basis as part of the NERC Reliability Standard. ATC recommends that the SDT either remove these sections or make them separate from the formal standard to eliminate any risk that these may be construed as requirements. An alternative method is to very clearly identify which parts of the standard are subject to compliance and considered mandatory and which are not considered requirements and are only for guidance in meeting the requirements. 3.) ATC believes the Measurements are well written and provide guidance on acceptable compliance evidence related to the requirement.4.) Measurement M2 related to R2 states that outages related to encroachments have records confirming no Real-Time observations of any MVCD encroachments. ATC feels this would be hard to prove as a negative. It could require one to show every single patrol or inspection has documentation stating no real time encroachments were observed.5.) Editorial Comment on Draft SDT VSLs for R2: To clarify the statements made for the Moderate, High and Severe VSLs. please add the verbiage, “into the MVCD” after “The TO had an encroachment.......”
	Response: **1) The formatting of these Rationale boxes is not set and will be addressed by NERC as the results-based standard-making procedural document is finalized.** **2) This issue will be addressed by NERC as the results-based standard-making procedural document is finalized.**		

	Organization	Yes or No	Question 8 Comment
	3) Thank you for your comments. **4) As stated in the Measure, an attestation serves as adequate evidence.** **5) Thank you for noticing this oversight. It will be corrected.**		
22	MRO's NERC Standards Review Subcommittee (nsrs)	Yes	1.) The NSRS notices that a previous draft concern on including Rationale Boxes plus Guidelines and Technical Basis as part of the NERC Reliability Standard. The NSRS recommends that the SDT either remove these sections or make them separate from the formal standard to eliminate any risk that these may be construed as requirements. An alternative method is to very clearly identify which parts of the standard are subject to compliance and considered mandatory and which are not considered requirements and are only for guidance in meeting the requirements. Such as; State within in the text that this information "Is not subject to enforcement". 2.) The NSRS believes the Measurements are well written and provide guidance on acceptable compliance evidence related to the requirement.3.) Measurement M2 related to R2 states that outages related to encroachments have records confirming no Real-Time observations of any MVCD encroachments. The NSRS feels this would be hard to prove as a negative. It could require one to show every single patrol or inspection has documentation stating no real time encroachments were observed.4.) Editorial Comment on Draft SDT VSLs for R2: To clarify the statements made for the Moderate, High and Severe VSLs. please add the verbiage, "into the MVCD" after "The TO had an encroachment......."
	Response: **1. This issue will be addressed by NERC as the results-based standard-making procedural document is finalized.** **2. Thank you for your comments.** **3. As stated in the Measure, an attestation serves as adequate evidence.** **4. Thank you for noticing this oversight. It will be corrected.**		

	Organization	Yes or No	Question 8 Comment
23	BGE Forestry Management	Yes	4.2.4 States that the Standard is not applicable to "...to Facilities .... located inside the fenced area of a switchyard, station or substation". This implies that anything within the fenced area of a switchyard, substation or power plant does not fall within the jurisdiction of FAC-003-2. Some fenced in areas could be very large and susceptible to vegetation encroachments issues. Suggest reference to "inside the fence" be removed.Disagree with R6. - Inspection Frequency. Very prescriptive. Please consider allowing TO's to select an annual frequency that best fits their requirements, such as calendar year, every growing season, every non-growing season, etc. BGE currently defines their inspection frequency as annually during the non-growing season, October 1 to May 1. BGE believes inspecting during the dormant season is a best practice due to the ability of the inspector to identify vegetation defects, especially off the ROW, which could be hidden during the growing season due to foliage, canopy cover, etc. Also, if a utility elects to leverage an advance technology, such as LiDAR, it provides the most effective results when LiDAR is utilize during the growing season, therefore allowing the results of the advance technology to enhance the fall to spring inspection cycle. Table 1 - Time Horizons, Violation Risk Factors, and Violation Severity Levels The VSL's for R7 all include "the Transmission Owner failed to complete.....% of its annual work plan (including modifications if any)". This is not clear to BGE. R7. allows plans to be modified due to changing conditions, for example ROW maintenance could be deferred to the following year due to mutual assistance agreements if the deferment does not violate the encroachment within the MVCD. The VSL implies this is a violation since the "modification" deferred a certain percentage of the planned worked to the following year, therefore 100% of the planned worked wasn't completed. If the modification was excluded, than 100% of the planned work would have been completed.
	Response: 1. **Regarding station boundaries, overall industry consensus is that line-based vegetation programs do not apply inside the station boundary. The SDT believes that "fence" is the best overall term for a station boundary.** 2. **While the SDT lauds BGE's approach, it feels that a calendar year basis affords sufficient flexibility for BGE and other TOs to schedule their inspections.**		

	Organization	Yes or No	Question 8 Comment
	3. The Standard suggests that the TO will begin with an original plan which may then be modified; it is implicit that measurements of plan completion are against the modified plan, not against the original plan.		
24	MidAmerican Energy	Yes	Any references to "observed in real time" should be removed. Vegetation contacts must be verified and references to real time are inappropriate. This causes difficulties in proving a negative in real time.
	Response: The SDT believes that the commenter has misinterpreted the requirement. It is not necessary for the TO to continuously observe; rather, a violation can only be reported if observed in real time.		
25	NERC Staff	Yes	**Effective Dates** • The first item should be re-written to "First calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval is required." • The second item is not needed and should be removed. • The third item is okay but the phrase "where explicit regulatory approval is not required" should be removed. **Exceptions** • Identifying a critical line and then waiting 12 months to perform vegetation management is counter to the risk avoidance strategy that the standard is attempting to accomplish. In effect, this standard permits an entity to identify a major WECC path or an IROL just prior to peak season and then not complete any vegetation management activities until just before the next season 12 months later. This is wholly inappropriate. The Planning Coordinator will identify these lines sufficiently far in advance that the 12-month window will prevent encroachments

	Organization	Yes or No	Question 8 Comment
			• Using the phrase "an element of an IROL" seems confusing because "Element" is a term defined in the glossary. Further, IROL is an identified limit, not a physical component. This should be reworded to say "a facility that is identified to be part of an interface or path impacting an IROL." This is also seen in R1 and R2 and needs to be adjusted there as well. The industry has reviewed this language and has found it to be sufficiently clear. • For newly acquired assets, the 12 month window may be appropriate, but there needs to be a much nearer term inspection undertaken to identify "risky" vegetation. **Definition** • The modified definition assumes the ROW is maintained, which may not be the case (for instance, if a newly acquired asset has not yet been acted upon). An entity could interpret the new definition to indicate that the new owner cannot be performing an initial vegetation inspection if the ROW has not yet been maintained. The phrase "maintained transmission line" should be changed to "applicable transmission line." • The inclusion of the phrase "which may be combined with a general line inspection" is unnecessary and should be removed. In fact, the current definition does not restrict combining the inspection with other field visits, while in the proposed definition that vegetation inspection can only be combined with a general line inspection. **Objectives (Section 3)** • NERC staff is concerned that the purpose states "that could lead to Cascading." This qualifier limits the purpose of the standard, which should be to prevent vegetation-related outages. The more outages there are, the less the overall system reliability; it does not necessarily have to lead to

	Organization	Yes or No	Question 8 Comment

			Cascading to be significant and represent a reasonable risk to the BES.
			• The term "maintain" might be better than "improve."
			
			Applicability (Section 4)
			• 4.1 Functional Entities
			• Noticeably absent from the standard is coverage for transmission facilities that connect generators to the interconnected bulk power system. As such, the team should add Generator Owners to the applicability and include such language that was proposed by the ad hoc team: transmission facilities that connect generators to the bulk power system that exceed two spans from the fence-line of the generating plant; coupled with the previous discussion, this provides complete coverage for all transmission facilities and switchyards and substations. This is what is needed to ensure no gaps in vegetation management coverage.
			• 4.2 Facilities
			  o The identification of critical facilities herein does not recognize the overarching criteria that are being developed in support of the PRC-023 order, and in some respects, in response to Order 693 directives to define the criteria for "critical facilities." The FAC-003-2 SDT should work in conjunction with the PRC-023 team, which is establishing a set of criteria for identifying critical facilities such that the outcome across all NERC standards is consistent.
			• "Transmission line" should be capitalized as a NERC-defined term.
			  o 4.2.4: This exclusion seems strange. It would appear that there are no expectations for vegetation management in switchyards, which is unacceptable. We should be able to develop language that requires that a Transmission Owner or Generator Owner maintain vegetation within fenced areas of the

	Organization	Yes or No	Question 8 Comment
			switchyard, station, or substation to the same clearances as one does for the ROWs, without necessarily obligating them to an annual cycle of inspection or management. o **Requirement R4** • "Qualified personnel" should be defined. In the Rationale, some examples are listed, but who else counts as "qualified field personnel"? This was intended to be an incomplete partial list. • "At any moment" is an unnecessary qualifier and should be removed (same for M4). • With respect to the phrase "intentional time delay," intent is a tricky thing to prove. Most standards set clear timelines which kick in regardless of intent, because it diminishes reliability to base a standard on intent. The SDT should consider doing so here. **Requirement R5** • NERC staff is confused by the overall purpose of this requirement. It appears to be a defense to a possible violation for failure to perform some planned vegetation work, but it flips it around and makes it a requirement. A better approach would be to just deal with this in addressing the mitigating/aggravating factors under a violation of R1 and R2. This concept is already part (R1.4) of the existing in-force FERC-approved FAC-003-1, but has been renamed to avoid conflict with terminology in the current NERC compliance guidelines. • The team should be more specific with respect to expectations for "corrective action." There needs to be an expectation that the corrective action needs to maintain an equivalent level of performance consistent with the intent of the vegetation management program. This could include, for example re-

	Organization	Yes or No	Question 8 Comment
			rating lines to reduce max sag until the condition is rectified, enhanced inspection cycles to monitor conditions, etc. It would be useful to define a metric for the success of corrective actions. • The team should be clearer on what constitutes a “constraint.” Is it only legal constraints? One interpretation could be resource constraints, which would certainly not be appropriate in this context. The phrase “due to constraints” is also used in the Rationale section. In this context, “constraint” appears to mean congestion on a transmission line. This seems very different from being “constrained from performing planned vegetation work.” In fact, the existence of congestion on a line does not necessarily create risk. We would not want entities to make the economic determination that they will put off required vegetation work because it would cost too much in energy sales profits. **Requirement R6** • It would appear necessary to require the use of the inspection information to guide or modify program development as is identified in the Rationale box accompanying the requirement. This is referred to in R7 but is not identified as an expectation from R6. • What are "all applicable transmission lines"? Are those lines covered by both R1 and R2? Clarify this. • “Once per calendar year" requires more guidance. Would two inspections on 12/31/2010 and 1/1/2011 satisfy this requirement? Shouldn't there be a requirement to space these inspections out? Recommend: once per calendar year with no more than 15 months between inspections. • The last sentence of R6’s Rationale states that “Transmission Owners should consider local and environmental factors that could warrant more frequent inspection.” But the way the

	Organization	Yes or No	Question 8 Comment

			requirement is written, there is no basis for requiring anything more frequent than once per calendar year. If the intent is to have stricter timelines for different registered entities, then the standard would need to be revised.
			
			Compliance
			• Additional Compliance Information
			  o Categories of Sustained Outages
			    ▪ Category 3 (Fall-ins from outside the ROW) should be reinstated. Even if it is not required by the standards, Category 3 reporting should be kept. The SDT believes that the current NERC TADS process captures such information adequately.
			    ▪ There is currently a public bulletin to encourage Transmission Owners to report Category 1 and 2 outages within 48 hours. The SDT should consider adding this as a requirement and including it in the new standard as such. The SDT has considered your suggestion and believes that the recognized requirement to promptly self-report any potential violations is sufficient.
			
			VSLs
			• The VSL for R3 should be shifted to an approach that simply counts the missing elements: Thanks for your comments. The SDT has modified the VSLs for R3.
			  o lower = missing one element
			  o moderate = missing two elements
			  o high= missing three elements
			  o severe = not having documents
			• The VSL for R4 uses the phrase “vegetation threat,” which needs to either be conformed to the text of the drafting team or defined. This VSL also uses the phrase “intentional delay” A

	Organization	Yes or No	Question 8 Comment
			truly intentional delay should be labeled as severe, not just high. (And as already stated, intent is a very tricky thing to prove.) In the context of the requirement, Measure and VSL, the term "vegetation threat" is self-evident. Refer to the SDT's earlier reply regariding "intentional delay". • For the VSL for R5, there may be ways to differentiate violations based on whether the entity identified appropriate corrective actions (versus missing obvious alternatives), attempted corrective actions but failed, considered alternative corrective action, etc. The SDT has considered this but has not identified a good means of differentiation. Additionally, industry stakeholders have not offered any means of differentiation. The SDT would welcome a proposal. • For the VSL for R6, the SDT should differentiate between the criticality of different lines. At the very least, a failure to inspect R1 lines should be a more severe violation than a failure to inspect R2 lines. The risk to the system is properly addressed by the VRFs, not by the VSLs. • The VSL for R7 should perhaps be differentiated based on whether the incomplete work related to critical versus non-critical or less critical lines (i.e., R1 lines vs. R2 lines). The risk to the system is properly addressed by the VRFs, not by the VSLs. **Guidelines and Technical Basis** • R1/R2 o "If an investigation of a fault by a qualified person confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered a Real-time observation": This is an important statement and should be included as part of the requirement itself. The SDT feels that this is really more of a "Measure" issue than a "Requirement" issue, and is adequately captured in M1. • R3

	Organization	Yes or No	Question 8 Comment
			o With respect to the phrase "an adequate transmission vegetation management program," the standard talks about factors to consider, but the requirement does not include any provisions on which to base a determination of adequacy. NERC staff believes it should. With NERC's movement to the results-based standard-making techniques, this is an outstanding issue that can best be resolved once RBS techniques are firmly established. o The guideline states, "This approach provides the basis for evaluating the intent, allocation of appropriate resources and the competency of the Transmission Owner in managing vegetation," but nothing in the requirements actually provide explicitly for such evaluations. The SDT asserts that with the totality of R3, M3 and associated VSLs, it is possible for the auditor to assess the TO's intent, competency, etc. • R4 o "Cellular service or two-way radio disabled" should not be considered an acceptable unintentional delay. This seems to be within the entity's control: there may be a difference between whether the cell service problems are due to network problems as opposed to the entity failing to charge the phone or pay the bill. The SDT has considered the comments, but believes the verbiage is adequate. o "Remote field locations" should not be considered an acceptable unintentional delay. This is not entirely beyond the registered entity's control. There may be a difference between a work site that is isolated from radio or cellular networks versus the fact that the employee simply left the radio in the truck. The SDT has considered the comments, but believes the verbiage is adequate. o "Vegetation-related conditions that warrant a response" should be defined in the standard. Qualified personnel

	Organization	Yes or No	Question 8 Comment
			are ab;le to assess the conditions as called for in the Requirement. o It is not clear to NERC staff that a lineman or an arborist is capable of completing “an assessment of the possible sag or movement of the conductor” out in the field in real time. However, if this is the expectation, it should be written into the requirements. The SDT believes it is necessary to rely on field personnel for routine decisions in the field, and that it is impractical and unworkable for engineering or survey teams to examine every questionable site. The SDT has considered the comments, but believes the verbiage is adequate. o The fourth paragraph states that the “Transmission Owner has the responsibility to ensure the proper communication…” Earlier in this section, however, it says that the condition of the communication system is not considered to be intentional delay. This inconsistency needs to be addressed. This sentence should also include a requirement for correcting the vegetation encroachment. The SDT agrees with your observation and will clarify the wording to indicate communication “processes” between field personnel and control centers are the issue being addressed. o The phrase “minutes or hours” is used in the final sentence of the fourth paragraph of this sentence. This detail should be written more clearly and written into the standards. Is 24 hours still hours? What about 48 hours? The SDT has conceived of cases where a 10-hour or more delay may be perfectly acceptable, but others where a 10- or 20-minute delay is inexcusable. The SDT believes that no rigid timeline is appropriate. • R6 o With respect to the following sentence, beginning with “Therefore it is expected,” NERC staff is concerned that

	Organization	Yes or No	Question 8 Comment
			nothing in the requirement actually makes this expectation enforceable. It would be best to require each TO that experiences a vegetation related sustained outage to investigate the outage and make revisions to its TVMP if the investigation shows that the growth rates of vegetation under the TO's control do not match those anticipated in the TVMP. The primary definition of "expected" is "looking forward to a probably occurrence", not a "required activity," and so the SDT believes that the verbiage is appropriate. • R7 o The second paragraph states that "recent line inspections may identify unanticipated high priority work." But the fifth bullet in R7 does not indicate that the higher priority work was identified in a recent line inspection. R7 should be revised to make that caveat clear. The SDT suggests that it is unnecessary to state that the TO will use all information available to it (including inspection results) in identifying unanticipated high-priority work. o The second paragraph references "Modifications to the annual work plan." Presumably, these modifications would not excuse compliance with R1, R2, and R6. That should be made clearer in the requirements. Thank you for the comments. **Table 3** • None of the requirements actually reference this table. That should be modified. Thank you. The Table will be removed. •
	Response:		

	Organization	Yes or No	Question 8 Comment
	Effective Dates **The SDT assumes that NERC staff will correct implementation timetable conflicts.** **Exceptions** **The SDT considered such language, but ultimately determined that it was unnecessary, partly because the response to "hot-spot"-type conditions is not part of this standard.** **Definition** • **Thank you for your excellent comments. The SDT has made changes to meet this concern.** • **Previous overwhelming industry comments have dictated the need for the SDT to clarify this language as it exists in the current draft. The current definition offers no restrictions that the vegetation restriction may only be combined with a general line inspection.** **Objectives (Section 3)** • **The Purpose as currently stated reflects broad industry consensus that earlier Purpose statements were over-reaching.** • **The Purpose as currently stated reflects broad industry consensus.** **Applicability (Section 4)** • **Re: generators - There is a NERC GO/TO team established to address this issue.** • **Re: critical facilities - While the SDT is aware of the interest in FERC to consolidate tests or criteria for so-called "critical" facilities, NERC leadership have indicated to FERC staff its commitment to separate efforts for use by PRC-023 and this standard.** • **Re: capitalizing Transmission Line - The SDT agrees and thanks you for your comments.** • **Re: 4.2.4 - Wide industry consensus is that line-based vegetation programs should not apply inside the station boundary. Also, as previously mentioned, another NERC team is examining the TO/GO issue.** **Requirement R4** • **Re: qualified personnel - The SDT changed the language to confirmation by the Transmission Operator.** • **Re: "At any moment" - The SDT believes that "at any moment" is a necessary but sufficient qualifier.** • **Re: "intentional time delay," - The SDT has considered this. FERC has already approved other standards with the same language.**		

	Organization	Yes or No	Question 8 Comment
	Requirement R5 • Re: corrective action - Past and recent industry comments indicate little confusion on this portion of the Standard. • Re: constraints - Past and recent industry comments indicate little confusion on this portion of the Standard. **Requirement R6** • Re: inspection information - The SDT suggests that it is unnecessary to state that the TO will use all information available to it (including inspection results) in developing its annual plan. • Re: “all applicable transmission lines” - Please refer to section 4 (“Applicability”) of the draft. • Re: calendar year - The SDT posed the question of inspection frequency to the overall industry in an earlier posting and received general consensus that a one-year interval would be appropriate. • Re: Rationale - The SDT does not intend that stricter timelines be rigidly defined or employed. **Compliance** • Re: Category 3 (Fall-ins from outside the ROW) - The SDT added this back in. • Re: Public bulletin - The SDT has considered your suggestion and believes that the recognized requirement to promptly self-report any potential violations is sufficient. **VSLs** • Re: VSL for R3 - The SDT has modified the VSLs for R3. • Re: VSL for R4 - In the context of the requirement, Measure and VSL, the term “vegetation threat” is self-evident. Refer to the SDT’s earlier reply regarding “intentional delay”. • Re: VSL for R5 - The SDT has considered this but has not identified a good means of differentiation. Additionally, industry stakeholders have not offered any means of differentiation. The SDT would welcome a proposal. • Re: VSL for R6 - The risk to the system is properly addressed by the VRFs, not by the VSLs. • Re: VSL for R7 - The risk to the system is properly addressed by the VRFs, not by the VSLs. **Guidelines and Technical Basis** • Re: R1/R2 - The SDT feels that this is really more of a “Measure” issue than a “Requirement” issue, and is adequately captured in M1. • Re: R3 – o With NERC’s movement to the results-based standard-making techniques, this is an outstanding		

	Organization	Yes or No	Question 8 Comment
	issue that can best be resolved once RBS techniques are firmly established. o The SDT asserts that with the totality of R3, M3 and associated VSLs, it is possible for the auditor to assess the TO's intent, competency, etc. • Re: R4 - o Re: "Cellular service or two-way radio disabled" - The SDT has considered the comments, but believes the verbiage is adequate. o Re: "Remote field locations" - The SDT has considered the comments, but believes the verbiage is adequate. o Re: "Vegetation-related conditions that warrant a response" - Qualified personnel are able to assess the conditions as called for in the Requirement. o Re: "assessment of the possible sag or movement of the conductor" out in the field - The SDT believes it is necessary to rely on field personnel for routine decisions in the field, and that it is impractical and unworkable for engineering or survey teams to examine every questionable site. The SDT has considered the comments, but believes the verbiage is adequate. o Re: The fourth paragraph - The SDT agrees with your observation and will clarify the wording to indicate communication "processes" between field personnel and control centers are the issue being addressed. o Re: The phrase "minutes or hours" - The SDT has conceived of cases where a 10-hour or more delay may be perfectly acceptable, but others where a 10- or 20-minute delay is inexcusable. The SDT believes that no rigid timeline is appropriate. • Re: R6 - o Re: sentence beginning with "Therefore it is expected," - The primary definition of "expected" is "looking forward to a probable occurrence", not a "required activity," and so the SDT believes that the verbiage is appropriate. • Re: R7 - o Re: The second paragraph - The SDT suggests that it is unnecessary to state that the TO will use all information available to it (including inspection results) in identifying unanticipated high-priority work. o Re: The second paragraph references "Modifications to the annual work plan." - Thank you for the comments. Table 3 • Thank you. Table 3 has been removed.		
26	FirstEnergy	Yes	FE has the following additional comments:1. In the SDT consideration of

	Organization	Yes or No	Question 8 Comment
			comments from Draft 3, it was indicated that "The subcommittee will ask that NERC's legal department write a statement for addition to each standard to clarify which parts/elements of the standard are mandatory and enforceable and which are provided only as information". We would appreciate this statement be placed into the standard before the final ballot so stakeholders have an opportunity to review and comment on the wording.2. We cannot comment on the Technical Reference Document since the latest draft was not posted for review. Does NERC intend to post this at a later time? If so, we ask that NERC give the industry enough time to adequately review the document so that we can provide quality feedback.3. In the Guidelines and Technical Basis Section, in the first paragraph of Requirement R5, second sentence, the word "temporarily" should be removed since it was removed from the requirement.
	Response: **The SDT thanks you for your comments.** **1) The NERC legal department has been contacted to provide a statement to clarify which parts/elements of a standard are mandatory and enforceable and which are provided only as information. This statement is nearing finalization and when completed will be posted as a separate document when the next draft of FAC-003-2 is posted.** **2) The Technical Reference Document is not a mandatory and enforceable document but your feedback is definitely appreciated once the document is finalized. The Technical Reference will be updated during the next ballot which will start during early August. The SDT will finalize the Technical Reference document at the August meeting in Toronto, ON which is scheduled from 8/17-8/19/10 and will post for comment.** **The word 'temporarily' has been removed from the Guidelines and Technical Basis as requested. Thank you for your comment.**		
27	Ameren	Yes	Funding Adjustments (increase or decrease) - need more description to imply only when planned vegetation work is "over and above".
	Response: Thank you for your comment. The SDT believes your observation and question is the same as voiced in Question 5. As stated in the SDT's response to Ameren's Question 5, we reviewed the Funding Adjustment example for R7 and feels this is a valid reason for modifying the Annual Plan keeping in mind that a modification must not place the transmission system at risk of vegetation encroachment into the		

	Organization	Yes or No	Question 8 Comment
	MVCD.		
28	Hydro One	Yes	Hydro One wants to thank the SDT for the effort that has gone into developing this proposed revision to FAC-003. Overall the new version is consistent with FERC Order 693 and will be a straightforward, workable, and auditable standard. One item requiring clarification and change is the Active ROW definition. The recent addition of a centerline distance to edge of Active ROW is not acceptable. In many areas design standards allow a smaller ROW width with no compromise to “cleared width” or tree related reliability of the line. The SDT needs to address this issue. In R5, the phrase 'where a transmission line is put at potential risk due to the constraint' should be better defined. This is vague and could lead to inconsistent practices between utilities. All undesirable species on the full width of the ROW are defined as 'potential risks to the transmission line' regardless of height or location at the time of vegetation management. Interim corrective action should only be required when the potential risk is approaching the imminent threat classification.
	Response: The SDT thanks you for your response. Your objection to our attempt to define a minimum width of the Active Transmission Right of Way was very similar to many other commenters. The SDT has subsequently revised the definition of ROW. **The issue you mention with R5 and “potential risk to the system” is understandable. The SDT changed this.**		
29	Idaho Power Company	Yes	I would like to see something more from NERC to clear the way for utilities to do vegetation management on federal lands that will allow timely vegetation management without delays from these federal entities.
	Response: **Thank you for your comments. This Standard places requirements on the Transmission Owners, not on landowners. There is no legal mechanism for this Standard to take rights from property owners and assign them to the Transmission Owner. There is joint UAA/EEI Task Force that is working on an MOU with the Federal Agencies to address these issues which are outside the purview of NERC Reliability Standards.**		
30	Idaho Power	Yes	I'd like to see language or NERC support to encourage federal agencies to expedite vegetation management maintenance requests and minimize the

	Organization	Yes or No	Question 8 Comment
			barriers to perform work on federal lands.
	Response: Thank you for your comments. This Standard places requirements on the Transmission Owners, not on landowners. There is no legal mechanism for this Standard to take rights from property owners and assign them to the Transmission Owner. There is joint UAA/EEI Task Force that is working on an MOU with the Federal Agencies to address these issues which are outside the purview of NERC Reliability Standards.		
31	Dominion	Yes	In R4 and M4, the phrase "without any intentional time delay" has been added. We recommend removing this language from the requirement as it is not possible to measure intent.
	Response: Thank you for your comment. Please refer to the SDT response to NERC staff above regarding R4.		
32	Consolidated Edison Company of New York Inc	Yes	In R5, the SDT should better define the phrase 'where a transmission line is put at potential risk due to the constraint.' This is rather vague and could lead to inconsistent practices between utilities. Con Edison defines all undesirable species on the full width of the ROW as 'potential risks to the transmission line' regardless of height or location at the time of vegetation management. Interim corrective action should only be required when the potential risk is approaching the imminent threat classification.
	Response: The SDT thanks you for your comments. As described in the Technical Reference document (See Page 30), R5 is not intended to address situations where the transmission line is not at potential risk, meaning risk of a Sustained Outage, and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the Transmission Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action. However, in situations where transmission line reliability is potentially at risk due to a constraint, the Transmission Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line.		

	Organization	Yes or No	Question 8 Comment
33	Orange and Rockland Utilities, Inc.	Yes	In R5, the SDT should better define the phrase 'where a transmission line is put at potential risk due to the constraint.' This is rather vague and could lead to inconsistent practices between utilities. Orange and Rockland Utilities, Inc. defines all undesirable species on the full width of the ROW as 'potential risks to the transmission line' regardless of height or location at the time of vegetation management. Interim corrective action should only be required when the potential risk is approaching the imminent threat classification.
	Response: The SDT thanks you for your comments. As described in the Technical Reference document (See Page 30), R5 is not intended to address situations where the transmission line is not at potential risk, meaning risk of a Sustained Outage, and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the Transmission Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action. However, in situations where transmission line reliability is potentially at risk due to a constraint, the Transmission Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line.		
34	Entergy Services	Yes	ITEMS of concern listed below:ITEM 1: Page 13 of the Standard Draft 4 under Add'l Compliance Information - Periodic Data Submittal......Clarify if Immediate Reporting is expected for outages in Outage Categories 1A, 1B, 2, or 4........or if Quarterly Reporting is all that is expected. It does not specifically say that IMMEDIATE Reporting is Required for any outage type. It is assumed that IMMEDIATE reporting is required for some outages, but is unclear.ITEM 2: Agree that text boxes being used for additional clarity is a benefit if used in a correct and clear manner, but it needs to be specifically stated in the document that the text boxes are to be used for reference only, we will not be required to specifically follow the language in the rationale, and that and each utility should specify their own exact process for addressing each Requirement.ITEM 3: Language should be added to the Guideline and Technical Basis Section to clarify or re-state that this section that this section is for assisting entities in understanding how to comply with the standard but does not contain mandatory actions/activities.ITEM 4: Please clarify defining factors that constitute "wind shear or fresh gale" as referenced in Section 4.4 Other. This is a very unclear interpretation and will most likely be interpreted

	Organization	Yes or No	Question 8 Comment
			differently by all involved if not specified.
	Response: Thank you for your comments. **ITEM 1: There is no requirement in this Standard for immediate reporting of any vegetation outage to the TO's RE. The TO's RE may require more frequent reporting or immediate reporting of any vegetation related outage. There may be other standards that apply to any transmission line outage that require immediate notification to the RE, NERC FERC, FBI, DOT and/or DOE. The SDT has considered your suggestion and believes that the recognized requirement to promptly self-report any potential violations is sufficient.** **ITEM 2: The Rationale boxes are intended to provide clarity and foundation behind each requirement. They are not a part of the requirement and are not sanctionable, as such. You are correct that every TO is required to structure its TVMP to comply with the standard as vegetation conditions exist. The NERC legal department has been contacted to provide a statement to clarify which parts/elements of a standard are mandatory and enforceable and which are provided only as information. This statement is nearing finalization and when completed will be posted as a separate document when the next draft of FAC-003-2 is posted.** **ITEM 3: The Guideline and Technical Reference paper Disclaimer on Page 6 of the document clearly states that the supporting document is supplemental to the reliability standard FAC-003-2 – Transmission Vegetation Management and does not contain mandatory requirements subject to compliance review.** **ITEM 4: Wind Shear and Fresh Gale are defined terms by the National Oceanic Atmospheric Administration (NOAA). Fresh gale is defined as straight line winds of between 39-46 mph. Wind Shear according to NOAA is a complicated formula that no one will ever use. Wind Shear definition according to NOAA Glossary is "The rate at which wind velocity changes from point to point in a given direction (as, vertically). The shear can be speed shear (where speed changes between the two points, but not direction_, direction shear (where direction changes between the two points, but not speed) or a combination of the two.**		
35	Northeast Power Coordinating Council	Yes	NPCC wants to thank the SDT for the effort that has gone into developing this proposed revision to FAC-003. Overall the new version is consistent with FERC Order 693 and will be a straightforward, workable, and auditable standard. One item requiring clarification and change is the Active ROW definition. The recent addition of a centerline distance to edge of Active ROW is not acceptable. In many areas design standards allow a smaller

	Organization	Yes or No	Question 8 Comment
			ROW width with no compromise to “cleared width” or tree related reliability of the line. The SDT needs to address this issue. In R5, the phrase 'where a transmission line is put at potential risk due to the constraint' should be better defined. This is vague and could lead to inconsistent practices between utilities. All undesirable species on the full width of the ROW are defined as 'potential risks to the transmission line' regardless of height or location at the time of vegetation management. Interim corrective action should only be required when the potential risk is approaching the imminent threat classification.
	Response: The SDT thanks you for your response. Your objection to our attempt to define a minimum width of the Active Transmission Right of Way was very similar to many other commenters. The SDT has revised the definition of ROW. **The issue you mention with R5 and “potential risk to the system” is understandable. The SDT amended the language.**		
36	Arizona Public Service Company	Yes	Qualifications needs to be put back in the standard. There needs to be a clearance 1 requirement.
	Response: Thank you for your comments. Training and qualifications are best addressed in the NERC PER standards. Additionally please refer to the SDT response to question 8, comment 42, regarding the issue of Clearance 1.		
37	Xcel Energy	Yes	R1 & R2 states that “types of encroachments include:” - is the way this is worded intended to imply there can be other types of encroachments that are not listed? If not, then rephrase the leading sentence to be definitive and indicate that the types are the only categories to be considered. We suggest that the wording from the prior draft, i.e., “ . . . limited to”.MCVD should be a defined term in the glossary, not in a “Rationale” box.R1 “1” should Real-time be capitalized to reflect the glossary definition? The term is used as “real time”, “Real time” and “Real Time” throughout the standard. This seems to be just a drafting issue, but the same term should be used consistently. Need to establish somewhere that the entity defines what constitutes a “qualified” person. Further, some portions of the standard use the term “qualified person” (e.g., see M1) and others reference “qualified field personnel” (e.g., see the Rational Box near M3). It seems that all references should be to

	Organization	Yes or No	Question 8 Comment
			"qualified field personnel."R1 & R2 are duplicative. It appears the only reason for the separation is so that different VRFs can be assigned. Why not just have 1 requirement and indicate that the VRF is High for one set of lines and Med for others?In general, the "Rationale" boxes force the requirement language into a difficult to read format.R5/M5 - the measures identified do not constitute "corrective actions", they merely identify documentation that work was attempted. Corrective actions should be "actions", such as establish an increased monitoring plan, re-rating of the line, removal from service, etc.R6 - Xcel Energy still believes the requirement in R6 that mandates an annual inspection is too onerous and is at odds with the results-based approach of these revisions. Xcel Energy urges the retention of the provision in the existing standard that allows the Transmission Owner to set the frequency of inspection. In some areas of the country, annual inspections may not be adequate. Yet in other areas, a longer inspection frequency may be perfectly reasonable and practical. Our point is that inspection frequency should not be treated as if it were "one size fits all". If treated this way, we feel this could pose a risk to reliability and is not likely to be cost-effective. The Transmission Owner should be allowed some flexibility. However, if the drafting team disagrees and determines that an annual inspection is to be mandated, Xcel Energy believes that an exception to the annual inspection is appropriate when a non-subjective advanced technology such as LIDAR is utilized to achieve actual clearance distances. This places the Transmission Owner in a situation where it can rationally determine that the objectively measured distances result in a situation where an inspection need not be performed within the next year. It is suggested that R6 be revised to read as follows: Each Transmission Owner shall perform a Vegetation Inspection of all applicable transmission lines at least once per calendar year, unless the Transmission Owner, based on a non-subjective advanced technology, such as LIDAR, determines that a longer inspection period is appropriate.The Effective Dates section is confusing - exactly when would this standard be in effect? It lists 3 approvals...do all three have to be met or just one?The reference to Major WECC transfer paths in the requirements introduces a weak element. The WECC major path designation and elements that comprise those paths should be controlled through a robust process and easily available to WECC members. Currently, there are some concerns around that process in general.NERC's concerns regarding reporting vegetation related outages within 48 hours

	Organization	Yes or No	Question 8 Comment
			should be addressed or clarified in the Compliance section. (i.e., incorporate or indicate that this supersedes that recommendation). Ref: Public Notice - NERC Compliance Process #2008 - 001
	Response: Thank you for your comments. The yellow highlighting refers to commenter issues. The SDT response follows. **R1 & R2 states that "types of encroachments include:": To address your concern, there are only (4) types of failure- to- manage types of encroachment as defined in R1 and R2 as it relates to compliance with FAC-003-2. The SDT appreciates your perspective but believes the requirement as written is clear to the point of only four encroachment types.** **MCVD should be a defined term in the glossary, not in a "Rationale": This term refers to a Table of values that is clearly defined within the standard itself.** **The term is used as "real time", "Real time" and "Real Time" throughout the standard. : Thanks for identifying this inconsistency and the SDT will review and address as appropriate.** **Need to establish somewhere that the entity defines what constitutes a "qualified" person.: This was replaced with confirmed by the Transmission Owner.** **Further, some portions of the standard use the term "qualified person" (e.g., see M1) and others reference "qualified field personnel" (e.g., see the Rational Box near M3).: Thanks for recognizing this inconsistency. The term "qualified" was replaced with confirmed by the Transmission Owner.** **R1 & R2 are duplicative. It appears the only reason for the separation is so that different VRFs can be assigned. Why not just have 1 requirement and indicate that the VRF is High for one set of lines and Med for others?: The SDT is following the VSL and VRF Guidelines which required us to designate two requirements since the VRFs are different for the applicable lines in the two requirements.** **R5/M5 - the measures identified do not constitute "corrective actions", they merely identify documentation that work was attempted.: The measures in R5 are evidence that appropriate corrective action was taken by the TO. Trying to identify very specific actions would be prescriptive in nature and difficult to cover a broad spectrum of potential corrective actions.** **R6 that mandates an annual inspection is too onerous and is at odds with the results-based approach of these revisions: As stated in previous comment responses, the SDT was directed by Order 693 to set a minimum inspection criteria and the SDT feels that an annual inspection is a reasonable minimum frequency.** **Effective Dates section is confusing - exactly when would this standard be in effect? The SDT has revised the effective date language for clarity. Please refer to change in revised draft.**		

	Organization	Yes or No	Question 8 Comment
	WECC major path designation and elements that comprise those paths should be controlled through a robust process and easily available to WECC members. Currently, there are some concerns around that process in general. : This is an issue that needs to be directed to WECC rather than the SDT. **48 hours should be addressed or clarified in the Compliance section. (i.e., incorporate or indicate that this supersedes that recommendation). Ref: Public Notice - NERC Compliance Process #2008 – 001: This Public Notice is a requirement for a Regional Entity to report to NERC.**		
38	BC Hydro	Yes	1. R4 - There will likely be issues of definition over what constitutes an “intentional delay” in notification. The time for reasonable reporting needs to be quantified. 2. The standard references Tables 2 and 3 but there is no Table 1 in the document. This is confusing and should be renumbered. This is likely a carry over from an earlier draft where a Table 1 has been renamed or dropped. 3. As noted earlier in Q1, table 3 is poorly developed and should be revisited.C 4. How does one objectively measure compliance to MVCD distances? Use of LiDAR technology, laser rangefinders, etc. should be used and evidence of potential violations should be empirical and not based solely on subjective observations, even if they are performed by “qualified personnel”. 5. The technical document should include a glossary of all the acronyms used throughout the document as it has some excessive jargon and does not always read smoothly, especially compared to FAC-003- The use of explanation boxes is helpful.
	Response: **1 The SDT debated a set time limit. The team could not find a time that would fit all situations. Intentional would apply if a TO withheld notification after having confirmed that risk conditions exist.** **2 The standard has been revised** **3 The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of ROW.**		

	Organization	Yes or No	Question 8 Comment
	4 The determination of a potential violation should employ any technology available **5 SDT has defined unusual terms not found within the industry.** **6 Thank you**		
39	The United Illuminating Company	Yes	R4:In R4 the phrase: without any intentional time delay, is a concern. There is a time line between identification and reporting of an imminent hazard that represents the minimal time required to complete this Requirement. Any situation where the time between observation and reporting is greater than this minimal time line indicates a time delay occurred. It will be left to the compliance enforcement authority to determine if this delay was intentional or not. It is not proper for the test to be based on Intentional versus Non-Intentional. Using other synonyms such as reasonable, expeditious, prompt, immediate or without hesitation all introduce a qualitative not a quantitative attribute to the measurement. The Supplemental Reference for R4 indicates that the imminent threat requirement is measured in minutes or hours; again no guidance for enforcement. R4 would be improved with an explicit time requirement of 6 hours between observation and report. This is measurable and clear.R4 should be: Each Transmission Owner shall notify the control center holding switching authority for the associated transmission line no more than 6 hours of a qualified personnel confirm the existence of a vegetation condition that is likely to cause a Fault at any moment.Other commenter's will argue that 6 hours is arbitrary or unduly prescriptive. I believe it is in line with the Supplemental Reference and adds clarity to the enforcement process.M4 becomes Each Transmission Owner that has a vegetation condition likely to cause a Fault at any moment, as confirmed by qualified personnel, will have evidence that it notified the control center holding switching authority for the associated transmission line within 6 hours of observation.The Transmission Owner can use the inspection as evidence of the time of observation.Effective Dates: The effective dates in the implementation Plan is in a different form then UI was expecting. Effective Date 1 UI has no comment.Effective date number 2 implies that if the BOT approves the standard and FERC takes no action (neither approves, remands or withholds approval of the standard) then the standard will become effective in one year. This seems to create the possibility of an effective standard without enforceability.Effective Date number 3 implies that regardless of any action by FERC the standard will become effective at least

	Organization	Yes or No	Question 8 Comment
			one year following BOT approval. Again this creates an effective standard without enforceability. Also the use of "at least one year" does not add any clarity to when the Standard would be effective any way.
	Response: **Thank you for your comments. The SDT considered a fixed time as you offer. We rejected that alternative as the situations under which conditions are found that can cause a Fault at any moment vary widely based on the terrain, weather and available transportation and communication methods. This Requirement is directing the TO to communicate the condition as soon as the above mentioned constraints will allow.** **We have addressed your concerns by revising the effective date language.**		
40	FPL Corporate Compliance	Yes	R5 as written is vague. It leads to confusion in interpretation. FPL recommends the following wording.R5. The Transmission Owner shall certify each corridor or line section that it meets the standards it set forth under R3 until the next planned management cycle when it is completed. If a location in known to not meet the criteria defined under R3, a mitigation plan must be in place to prevent a violation of R1 or R2.R1 and R2 are too inclusive. They equate vegetation growing in to conductors from below the same as vegetation falling or blowing into the conductors from within the Active ROW. There is no evidence that a cascading event has ever been caused by the latter two events. This standard should concentrate on vegetation growing from below the conductor. Suggested wording of R1 and R2 is as follows.R1. Each Transmission Owner shall manage vegetation to prevent encroachment into the Minimum Vegetation Clearance Distance (MVCD) as shown in Table 2 from within the active ROW on of any line identified as an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions). Encroachments are determined by: 1. An encroachment, observed in real time, 4. An encroachment due to a grow-in from below the conductor in the active ROW that caused a Fault.R1. Each Transmission Owner shall manage vegetation to prevent encroachment into the Minimum Vegetation Clearance Distance (MVCD) as shown in Table 2 from within the active ROW on of any line that is not an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions). Encroachments are determined by:

	Organization	Yes or No	Question 8 Comment
			1. An encroachment, observed in real time, 4. An encroachment due to a grow-in from below the conductor in the active ROW that caused a Fault.
	Response: The STD recognizes that defining any risk is subjective. Removing the term does not change the fact that each TO must determine the risk and respond accordingly. **The SDT has placed reference to the different severity of the respective violations into R1 and R2. Both NERC and FERC are on record that fall-in and blow-in interruptions place sufficient risk to the system that they should be part of the standard.**		
41	MWDSC (METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA)	Yes	Requirement R4.uses the phrase "notify the control center holding switching authority for the associated transmission line" when a vegetation condition is confirmed which is likely to cause a Fault. Switching jurisdiction may be assigned to a manned substation located closer to a line rather than a remote 24/7 manned control center. However, the switching substation will notify its control center. The control center may need to notify and coordinate with its Balancing Authority or neighboring control centers. Suggest changing the phrase as follows: "notify the appropriate control center(s)for the associated transmission line"
	Response: The SDT thanks you for your comments. The example you provided in your comment is in compliance with the Requirement as written. The local procedure developed by a Transmission Owner may involve multiple notification steps but, as long as the proper operating personnel holding switching authority for that associated line is notified without any intentional delay, the Requirement is met. Due to multiple variations in utility notification procedures across North America, the SDT has decided to retain the existing language in the current draft.		
42	Southern California Edison Company	Yes	SCE questions the need for including the “Guidelines and Technical Basis” section within the body of the standard and is also curious as to the criteria used in developing new Table 3.SCE finds this Draft (4) to be the best work product thus far, and commends the SDT for its efforts and continued dedication to crafting a best-in-class standard.
	Response: The SDT thanks you for your comment. The ‘Guidelines and Technical Basis” is part of the format change with a “results based” standard. The idea is to bring some of the technical reference documentation into the Standard. This will hopefully make the entire Standard a more complete document and will reduce the need to have both the Standard and the Technical Reference Document in hand.		

	Organization	Yes or No	Question 8 Comment
	Table 3 was an attempt to define a "minimum width" of the Active Transmission Right of Way. This table, along with the footnote, has been removed from the Standard. The definition of Right of Way has been changed in the Glossary.		
43	Bonneville Power Administration	Yes	The basis of managing vegetation to MVCD in Table 2 (essentially withstand distances) will likely prove problematic. BPA believes NERC should develop an additional table that calls out minimum "buffers" based on attributes such as line voltage, line rating etc. This table should be a companion to Table 2. It is NERC's responsibility to regulate and we believe that they should do so. In this case, the loss of flexibility for the owners is not necessarily a bad thing.
	Response: The SDT thanks you for your comments. As described in the Background Section of the Standard, FAC-003-2 is being drafted utilizing a Results Based Standard approach. One component of this type of Standard is that requirements within a standard are not too prescriptive allowing for flexibility. An additional Table would be considered overly prescriptive and in direct conflict with our guidance. It is the Transmission Owner's responsibility to identify the 'buffers' that you mention, not NERC. Since conditions vary significantly across North America, maintaining this specific buffer distance may not be feasible for all utilities.		
44	Southern Company Transmission	Yes	The NERC Glossary of Terms provides a definition for Flashover. The Rationale boxes for R1 and R2 use the term "spark-over". This is inconsistent with other references in the Standard. Note that the term Flashover is used in footnote No.4. Please resolve the inconsistency between these terms.We are concerned FAC-003-2 is being developed under a zero tolerance philosophy, while other NERC standards do not adopt a zero tolerance philosophy. Industry performance under FAC-003-1 indicates the standard is working and that industry is responding to ensure reliability of the electric Transmission system.We would like to thank the SDT for the work they have put into developing the proposed draft.
	Response: **The SDT thanks you for your response. The technically correct term for the electric discharge through air is "spark-over". In the Technical Reference Document this term is used. The technical definition of "flash-over" refers to the electric discharge over the surface of insulation when the "withstand" of the air is less than the "withstand" of the insulation and the insulator "flashes over".**		

	Organization	Yes or No	Question 8 Comment
	However, the commonly used term in industry for both phenomena is “flash over”. The NERC Glossary definition has actually rolled the technical definition of both terms together into one definition. **The SDT has decided to use the term “flash-over” in all sections of the Standard except for the derivation of the Gallet equations in the appendix of the Technical Reference Document. Hopefully this will alleviate any confusion.** **The SDT recognizes that the current version of the Standard is zero tolerance and believes it is compelled to write the new version it that way. FERC staff and NERC assert that a revised standard cannot result in less reliability than the one it replaces, and, their belief is the current Standard is zero tolerance.**		
45	ITC Transmission	Yes	We were beginning to except Version 3 to the standard but with the addition of “Table 3, Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW” is totally unacceptable. This entire reference should be stricken from the standard. ITC can not support this table #3 and Version 4 is unacceptable.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of ROW in the NERC Glossary.		

Consideration of Comments on Initial Ballot — Project 2007-07 Vegetation Management FAC-003-2
Date of Initial Ballot: 7/9/2010 - 7/19/2010

Summary Consideration: In general, there were no common themes and as such each comment was responded to individually.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td>Kirit S. Shah</td><td>Ameren Services</td><td>1</td><td>Negative</td><td>(1) Need clarification on Footnote number 2 and Table 3 : Does this mean wider ROW easements will need to be acquired to be compliant or will this apply to ROW's for new circuits going forward? (2)R7 - Funding Adjustments (increase or decrease) - need more description to imply only when planned vegetation work is "over and above". (3) R5 - What constitutes a "potential risk"? Breaking the MVCD or getting close to it? (4) R7 - No work plan can ensure that NO vegetation encroachments will occur; can language be added similar to "to ensure that no vegetation encroachments 'from vegetation within the active right of way' occur within the MVCD"?</td></tr>
<tr><td colspan="5">Response:
(1) No, the SDT has re-established the concept of an Active Transmission Line ROW by changing the definition of Right of Way with the same principles which was almost universally accepted by industry. After thorough analysis of potential modifications to Table 3 and other alternatives, the team found no specific, prescriptive, or formulaic language which can be applied across the US, Canada and Mexico, thus the team reverted to the Active Transmission Line ROW, removed Footnote 2 and Table 3.
(2) The SDT limits the reasons for plan adjustment by whether the changes place the system at risk of a violation of the MVCD as defined in R1 and R2.
(3) The SDT recognizes that defining any risk is subjective. Removing the term does not change the fact that each TO must determine the risk and respond accordingly.
(4) The SDT has incorporated your suggestions.</td></tr>
<tr><td>Danny McDaniel</td><td>Cleco Power LLC</td><td>1</td><td>Negative</td><td rowspan="2">1. Encroachment into the MVCD should require the owner to take immediate corrective action to mitigate the threat. But such an encroachment should not be reportable as a violation. Owners may be hesitant to report if they known it is a violation. Recommend the SDT consider modifying the measures for R1 and R2 to be applicable only in the interruption of transmission facility or allow the reporting but don't make it a violation of compliance. R4 states "Each Transmission Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated transmission line when qualified</td></tr>
<tr><td>Bryan Y Harper</td><td>Cleco Utility Group</td><td>3</td><td>Negative</td></tr>
</table>

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

<table>
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<tr><td>Matthew D Cripps</td><td>Cleco Power LLC</td><td>6</td><td>Negative</td><td>personnel confirm the existence of a vegetation condition that is likely to cause a Fault at any moment" 2. In R4, the use of "intentional" is a vague term. As other standards prescribe, set a time at which the control center should be notified. R5 states: "Each Transmission Owner shall take corrective action when it is constrained from performing planned vegetation work, where a transmission line is put at potential risk due to the constraint." 3. In R5, the use of "potential risk" is a vague term. R5 should read as follows: Each Transmission Owner shall take corrective action when it is constrained from performing planned vegetation work. R7 states: "Each Transmission Owner shall complete the work in an annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD ...." 4. The first sentence should not include the phrase "to ensure no vegetation encroachments occur within the MVCD" since the requirement is to do the work in the work plan. The added phrase adds ambiguity, e.g., if there is an encroachment, is R7 violated since it does not meet the "ensure" phrase? Would this cause a double jeopardy situation with R1 and R2?</td></tr>
<tr><td colspan="5">Response:
1. The SDT discussed this issue at length. However, NERC and FERC interpret vegetation growing into MAID as too great a risk to allow. While MAID is replaced with the MVCD the risk is still there.
2. The SDT debated a set time limit. The team could not find a time that would fit all situations. Intentional would apply if a TO withheld notification after having confirmed that risk conditions exist.
3. The SDT removed the vague language.
4. There are opportunities for double jeopardy between R1/R2 and R7 without this language. The occurrence of double jeopardy has not been born out.</td></tr>
<tr><td>Saurabh Saksena</td><td>National Grid</td><td>1</td><td>Negative</td><td rowspan="2">1. The recent addition of a centerline distance to edge of Active ROW is not acceptable to National Grid. In many areas we use design standards that allow a much lesser ROW width with no compromise to “cleared width” or tree related reliability of the line. Instead of using the term “Centerline” as referenced on Table 3, the use of “outer phase” or “phase closest to tree line” would be more appropriate. 2. National Grid also has issues with the term "easements" in the definition and seek clarification on several questions - is there a reason the Active ROW only includes easements, not fee ownership, license or some other right to occupy and manage the ROW? Would Active ROW include “danger tree rights” on land?</td></tr>
<tr><td>Michael Schiavone</td><td>Niagara Mohawk (National Grid Company)</td><td>3</td><td>Negative</td></tr>
<tr><td colspan="5">Response: 1&2. The SDT thanks you for your comments. Based on your comment and others, the , the SDT has re-established the concept of an Active Transmission Line ROW by changing the definition of Right of Way with the same principles which was almost universally accepted by industry. After thorough analysis of potential modifications to Table 3 and other alternatives, the team found no specific, prescriptive, or formulaic language which can be applied across the US, Canada and Mexico, thus the team reverted to the Active Transmission Line ROW, removed Footnote 2 and Table 3.</td></tr>
<tr><td>Claudiu</td><td>GDS Associates, Inc.</td><td>1</td><td>Negative</td><td>All comments have been included in the NERC comment form.</td></tr>
</table>

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<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td>Cadar</td><td></td><td></td><td></td><td></td></tr>
<tr><td colspan="5">Response: Please refer to the SDT responses on the comment form.</td></tr>
<tr><td>Michael Gammon</td><td>Kansas City Power & Light Co.</td><td>1</td><td>Negative</td><td rowspan="2">Although the proposed FAC-003 standard has many improvements and advancements that are desirable over the existing FAC-003 standard, the handling and treatment of encroachments as proposed without consideration of recognizing an organizations efforts in responding to an encroachment situation makes this proposal less desirable and is a major concern regarding the risk that the associated penalties and assessments place on organizations.</td></tr>
<tr><td>Scott Heidtbrink</td><td>Kansas City Power & Light Co.</td><td>5</td><td>Negative</td></tr>
<tr><td colspan="5">Response: The SDT thanks you for your comments. Zero tolerance for vegetation caused outages is a stated goal of FERC and NERC as it relates to this standard. Quote from NERC:

Vegetation Management — While four transmission outages due to vegetation occurred in a single afternoon five years ago, preliminary data suggests that only six such outages occurred in the first six months of 2008 – none of which caused customers to lose power. Transmission line outages due to vegetation contact are still a cause for concern, however, and this remains a top priority for NERC. Through its standards and compliance enforcement, NERC now has a zero-tolerance policy in place, where the goal is to correct issues that may arise long before any customers are affected.

This policy is part of FAC-003-1 and in concept did not change with the proposed version. The SDT recognizes this concern and has developed gradation taking into account line criticality in VRF's and type of outage not contained in the current version FAC-003-1. Finally, It is also important to note that each and every incident or potential violation is investigated and addressed based on the specific circumstances surrounding the particular event. These investigations should necessarily take into consideration and recognize the utility's individual efforts in responding to an encroachment situation.</td></tr>
<tr><td>Thomas R. Glock</td><td>Arizona Public Service Co.</td><td>3</td><td>Negative</td><td>APS supports retention of FAC-003-1 as currently effective, as it is working well for the industry. APS does not support a change to this standard for the following reasons: o The minimum clearances must be sufficient to avoid any sustained vegetation-related outages for all applicable conditions. ? . ? Clearance 1 should remain in the standard as it ensures clear direction to the utility on how the system is to be maintained, and provides assistance to the Transmission Owners in dealings with federal land agencies on vegetation management issues. Elimination of the discretion in clearance 1 will significantly degrade this support. ? ANSI-A300 should remain in the standard. Though simply a footnote in the currently effective version, ANSI-A300 should be a requirement in the standard. Relevant Registered Entities should be held to following ANSI A-300 standards and BMP's for best management practices. o APS does not agree with the removal of 'fill in the blank' components where the Transmission Owner determines the requirement with no limits or direction. Examples include and "personnel requirements" in version 1. The SDT removed this requirement from the current version. ? Personnel qualifications should be remain a requirement. The standard should recognize certification programs through the International Society of Arboriculture that certify a minimum level of competence to manage</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
				a vegetation management program which required ongoing training and education to keep up with the latest technologies on UVM. ? There are other standards that require qualifications and training. ? The revised standard dilutes accountability for maintaining the full width of utilities easement. The active ROW should be wide enough to prevent outages caused by grow-in and blow-in events. ? The changes to R1, allowing a real-time observations to evidence encroachments, does not take into account all rated conditions and the time the recording was made. Real-time observations will not account for changing conditions and increase in load. Available technologies, such as LIDAR, can simulate all-rated conditions, contour and tree height to remove these potential trees hazards before an outage occurs. ? The utilities should be required to inspect all the lines annually. ? The standard should include a footnote that provides that a utility will not be held accountable for not completing its annual work plan if federal or state agencies fail to approve annual work plans within 90 days of submittal, or that takes into account the time it takes the utility to get approval.

Response: Thank you for your comments.

- **The SDT is changing the Standard in response to the SAR. The success of the existing standard will be preserved and enhanced with this revision.**
- **If vegetation is maintained as required in this draft of the standard in requirements R1 and R2, then no vegetation-related sustained outages, caused by vegetation from within the ROW, within the control of the TO can occur.**
- **Clearance 1 was a fill-in the blank requirement and did not provide the TO any new easement rights, or land permit rights across any lands whether those land be privately owned or publicly owned; therefore Clearance 1 remains removed from this draft. Furthermore, the relevance of Clearance 1 depends on several other factors such as length of maintenance cycles, inspection frequency and growth rates. R3 is now used as a more comprehensive method to address these concerns in lieu of a Clearance 1 requirement.**
- **In order to meet the SAR FAC-003 is required. ANSI-A300 is not sufficient to meet the SAR requirements and contains many elements that do not need to be related to transmission system electrical reliability.**
- **The SDT suggests that the submittal of a NERC SAR on the PER standards be considered to address any proposed personnel qualifications, certifications or training issues.**
- **The SDT is following NERC guidelines as they understand them.**
- **The SDT has re-established the concept of an Active Transmission Line ROW by changing the definition of Right of Way with the same principles which was almost universally accepted by industry. Outages arising from vegetation from outside the ROW are not violations of the standard. The SDT had determined this to be the most appropriate assignment of an area of maintenance responsibility considering the numerous variations in easements and permit rights across North America.**
- **The Standard requires the maintenance to be performed such that loading to Rating and Rated Conditions, and the dynamics of sag and sway are taken into consideration. Additionally any real time observations of encroachments into the MVCD are to be reported as violations of the standard. The SDT does not see the need to be prescriptive as to the technology or tools the TO used to be compliant with the Standard, but is confident that if the vegetation in maintained such that no encroachments are ever observed, and no outages are ever occur, then the reliability purpose of the standard will be fully accomplished. Furthermore, the results from a LIDAR survey are temporal in nature.**

Voter	Entity	Segment	Vote	Comment
Any program relying on LIDAR would incur a substantial cost with a long term commitment that may not be justified for many Transmission Owners. • **FERC requested a defined period for inspection. The SDT agrees with you that annual inspection is required. Therefore the SDT has made annual inspections a Requirement of this Standard. As to all lines versus applicable lines, FERC has accepted the 200 kV bright line for this standard. They did order the SDT to ensure that no sub-200 kV lines that are important to the Bulk Electric System are missing from the Applicability of the standard. The SDT has incorporated a FERC accepted test (as found in the referenced Standard) to make sure no such important lines are missing.** • **The SDT agrees that erroneous obstacles to compliance with the standard should be addressed. However, they cannot be resolved in this forum, or through language inserted in this standard. This Standard places requirements on the Transmission Owners, not on landowners. There is no legal mechanism for this Standard to take rights from property owners and assign them to the Transmission Owner.**				
John J. Moraski	Baltimore Gas & Electric Company	1	Negative	BGE feels that the new standard does nothing to improve reliability over the existing standard. Furthermore, it could be argued that it potentially diminishes reliability, based on the new MVCD vs. Clearance 2 guidelines. It also includes requirements which could be perceived as being more confusing than the existing requirements in the current standard, e.g., the Active Right-of-Way, Calendar Year Inspections, etc. The new standard, If adopted, would almost certainly require a complete restructuring of all TVMPs and related compliance processes, with no commensurate value-added for individual utilities or the industry in general. In addition, it would do little to enhance the overall intent of the standard, which is to improve vegetation-related transmission reliability in North America.
Response: The SDT thanks you for your comments. The SDT believes the proposed version addresses concerns outlined in FERC Order 693 and improves reliability of the BES. The industry overwhelmingly agrees the MVCD based on the Gallet Equation is superior to that of the Clearance 2 fill-in the blank requirement in the current version and in fact can be a greater distance depending on the basis used for Clearance 2 determination. Based on your comment and others, the SDT has re-established the concept of an Active Transmission Line ROW by changing the definition of Right of Way with the same principles which were almost universally accepted by industry. After thorough analysis of potential modifications to Table 3 and other alternatives, the team found no specific, prescriptive, or formulaic language which can be applied across the US, Canada and Mexico, thus the team reverted to a ROW definition, removed Footnote 2 and Table 3. While it is true that any change to the standard may result in changes to current documentation of practices and procedures (such as the TVMP), the SDT believes changes will be minor and be an improvement.				

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Paul Rocha	CenterPoint Energy	1	Negative	CenterPoint Energy believes the proposed FAC-003-2 is not a performance-based standard, despite being labeled as such, because it remains too focused on processes and procedures. CenterPoint Energy fails to see much difference in the approach from the current Standard. CenterPoint Energy believes a performance based requirement would provide performance criteria that an entity would be measured against. An example of a performance based requirement would be the following: R1. "Each Transmission Owner shall manage vegetation to prevent encroachment that results in no more than one (1) Sustained Outage per XXX circuit miles of applicable lines within any twelve (12) month period." M1. Each Transmission Owner has evidence that it had no more than one (1) Sustained Outage per XXX circuit miles of applicable lines within any twelve (12) month period. Examples of acceptable forms of evidence may include dated reports of vegetation-related Sustained Outages or dated attestations as to no vegetation-related Sustained Outages have occurred.
Response: The SDT thanks you for your comments. FAC-003-2 is a "results based standard" (RBS) with a stated objective to prevent outages that could lead to cascading. Any requirement that has an allowance for a certain number of outages does not meet that objective.				
Russell A Noble	Cowlitz County PUD	3	Negative	Cowlitz votes negative with reluctance over two items: 1. Requirement R4 has a qualitative nature in the statement "without intentional time delay" which will leave room for subjective judgment on the part of the auditor in determining intent or the state of mind of the Transmission Owner. Cowlitz understands the need to communicate to the control center a vegetation condition that may cause a Fault at any moment as soon as possible. In this light, it is not possible to set a quantitative time limit for this report to occur for all occasions. In one scenario, a very short time limit may be arguable due to the proximity of available radio/telephone communications. However, in another remote situation it may take up to several hours to access communication equipment after discovery. Compounding the problem is the need to document the time of day versus location progress of the vegetation inspector to establish a discovery time stamp; this is not covered in M4. Cowlitz suggests the following changes (see standards VAR-002-1, IRO-006-3, TOP-003-0, TOP-

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Bob Essex	Cowlitz County PUD	5	Negative	007-0 for similar verbiage): R4. Each Transmission Owner shall notify the control center holding switching authority for the associated transmission line when qualified personnel confirm the existence of a vegetation condition that is likely to cause a Fault at any moment as soon as possible, but no longer than one hour with the following exception: In areas where communication with the control center is not possible within one hour due to lack of radio/telephone service, the Transmission Owner shall document these areas along with the reasonable time frame for reaching radio/telephone service. 2. Cowlitz agrees with United Illuminating in that R7, as proposed, requires a VMP to be completed to ensure no encroachment occurs. The Supplemental Reference for R7 does not describe the requirement of the annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. The Reference states the requirement is established to diminish the risk of encroachment; very different from ensuring no encroachment. In the reference for R7 the word “ensure” is only used to describe that flexibility in the VMP is allowed to ensure the reliability of the Transmission System. M7 is measuring work plan completion not the prevention of encroachment. United Illuminating and Cowlitz suggest that R7 be changed to: Each Transmission Owner shall complete the work in an annual vegetation work plan to manage the prevention of vegetation encroachments occur within the MVCD. In this way, a violation of R1/R2 does not necessarily mean R7 is violated. The entity does not avoid a penalty for an encroachment because a violation of R1/R2 occurs for actual encroachment. If an encroachment occurs the compliance enforcement authority can review the entities vegetation management plan to determine if it is compliance with R7/M7.

Response: The SDT thanks you for your comments.

1. **The time required by the TO to report an issue is subject to many variables such as available communication for the area which could be a hike-in location with no radio or cell phone coverage. For this reason it is difficult to establish a time period which would fairly apply to all TO’s.**
2. **Please refer to the following responses to questions (which are responsive to your reference to your conncurrence with the United Illuminating):**

   Question 1: Comment 12

   Question 5: Comment 6

   Question 6: Comment 44

   Question 7: Comment 14

   Question 8: Comment 39

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Jason L. Murray	Alberta Electric System Operator	2	Negative	Due to slow vegetation growth rates in many parts of Alberta, not all transmission right-of-ways require annual inspection as required in R6. TOs should be able to include planned inspection cycles in their Transmission Vegetation Management Plan.
Response: Thank you for your comment. For the sake of consistency for all applicable entities, the SDT believes that an annual inspection complements the required annual work plan. The standard allows for both maintenance inspections and vegetation inspections to be performed concurrently. Additionally, annual inspections are useful to not only track growth, but also other potential issues such as identifying danger trees, landslides, erosion, and tree damage caused by animals.				
Ralph Frederick Meyer	Empire District Electric Co.	1	Negative	EDE agrees with the concers raised by United Illuminating and therefore also provides the following comments related to R7 and R4 for FAC-003-2. R4: The use of intentional time delay is a qualitative attribute and not a quantitative measure. It will lead to endless arguments over intentional versus non-intentional. EDE agrees with UI's comment: "In R4 the phrase: without any intentional time delay, is a concern. There is a time line between identification and reporting of an imminent hazard that represents the minimal time required to complete this Requirement. Any situation where the time between observation and reporting is greater than this minimal time line indicates a time delay occurred. It will be left to the compliance enforcement authority to determine if this delay was intentional or not. It is not proper for the test to be based on Intentional versus Non-Intentional. Using other synonyms such as reasonable, expeditious, prompt, immediate or without hesitation all introduce a qualitative not a quantitative attribute to the measurement. The Supplemental Reference for R4 indicates that the imminent threat requirement is measured in minutes or hours; again no guidance for enforcement. R4 would be improved with an explicit time requirement of 6 hours between observation and report. This is measurable and clear. M4 becomes Each Transmission Owner that has a vegetation condition likely to cause a Fault at any moment, as confirmed by qualified personnel, will have evidence that it notified the control center holding switching authority for the associated transmission line within 6 hours of observation." R7: R7, as proposed, requires a VMP to be completed to ensure no encroachment occurs. The Supplemental Reference for R7 does not describe the requirement of the annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. The Reference states the requirement is established to diminish the risk of encroachment; very different from ensuring no encroachment. In the reference for R7 the word “ensure” is only used to describe that flexibility in the VMP is allowed to ensure the reliability of the Transmission System. M7 is measuring work plan completion not the prevention of encroachment. EDE agrees with United Illuminating suggestion that R7 be changed to: Each Transmission Owner shall complete the work in an annual vegetation work plan to manage the prevention of vegetation encroachments occur within the MVCD. In this way, a violation of R1/R2 does not necessarily mean R7 is violated. The entity does not avoid a penalty for an encroachment because a violation of R1/R2 occurs for actual

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				encroachment. If an encroachment occurs the compliance enforcement authority can review the entities vegetation management plan to determine if it is compliance with R7/M7. EDE also agrees with concerns raised by FMPA that Periodic data submittals as written are really periodic self-certifications and ought to be named such, or 100% compliance reduced to a more reasonable target
Response: Thank you for your comment. The SDT believes that it was not prudent to suggest a quantitative time element for notification in R4. The technical reference offers examples of acceptable unintentional delays for your review. Confirmation that a threat actually exists due to vegetation is key. **Based on comments, the language in R7 has been modified.**				
Robert Martinko	FirstEnergy Energy Delivery	1	Negative	FirstEnergy appreciates the hard work of the drafting team, but unfortunately we must cast a Negative vote for the standard as written. If the SDT agrees with our comments below and makes the suggested changes, we will consider supporting this standard in the recirculation ballot. In the latest Draft 4, the SDT added a Table 3 titled "Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW". We do not support the addition of Table 3 because we believe it adds unnecessary prescriptiveness to the requirements. It is also not clear if this Table was intended to be mandatory because the only reference in the table is in Footnote #2. Furthermore, the SDT did not offer any rationale for the minimum distances shown. If the SDT feels this table is a useful tool that should be included in the standard, then we suggest adding it to the Guidelines and Technical basis section as optional information with a discussion of the basis for the values chosen. The standard being balloted includes an R1 and R2 detailing requirements for managing vegetation. In addition, the SDT has asked for industry feedback on an alternate R1/R2 through the comment form which may lead to changes to the standard after this initial ballot. FirstEnergy supports the alternate R1/R2 but as we stated in the comment form, we still need to see the final verbiage of the alternate R1/R2 along with their associated measures M1 and M2 which have not yet been developed. Therefore, we cannot support the standard until the alternate R1, R2, M1 and M2 are developed.
Kevin Querry	FirstEnergy Solutions	3	Negative	
Douglas Hohlbaugh	Ohio Edison Company	4	Negative	
Kenneth Dresner	FirstEnergy Solutions	5	Negative	
Mark S Travaglianti	FirstEnergy Solutions	6	Negative	
Response: Thank you for your comment. In response to comments regarding the addition of the "Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW" Table 3, the SDT agrees to remove this table and use the new definition of Right of Way. Additionally, language in M1/M2 has been modified based on comments received.				

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Frank Gaffney	Florida Municipal Power Agency	4	Negative	My biggest problem is with R1 and R2 "Each Transmission Owner shall manage vegetation to prevent encroachment that could result in a Sustained Outage of applicable lines .... Types of encroachment include: 1. An encroachment into the Minimum Vegetation Clearance Distance (MVCD) as shown in Table 2, observed in real time, absent a Sustained Outage, 2. An encroachment due to a fall-in from inside the active transmission line ROW that caused a vegetation-related Sustained Outage, 3. An encroachment due to blowing together of applicable lines and vegetation located inside the active transmission line ROW that caused a vegetation-related Sustained Outage, 4. An encroachment due to a grow-in that caused a vegetation-related Sustained Outage" One fundamental problem with all the standards is the demand for no faults, no errors, 100% compliance. Requirements 1 and 2 basically say that any vegetation related outage, except for blow ins from outside the ROW, is a violation. A few issues with this: How would we "prove" that an outage is vegetation related or not, and if vegetation related, where the vegetation came from? Would this be a "guilty until proven innocent" paradigm, e.g., if we don't know what the cause was, then we assume guilty, or an "innocent until proven guilty" paradigm, e.g., clear evidence is needed to prove guilt? Current compliance monitoring and enforcement methods are to assume guilt with the need for clear evidence of innocence until a hearing is requested, at which point the paradigm is reversed. If this is how we expect it to happen? I could see a large number of "Possible" and "Alleged" violations where the cause of the sustained outage or the source of the vegetation is unknown, and a large number of hearings, unless we begin with the paradigm with "innocent until proven guilty", which is not the approach monitoring and enforcement take currently. The requirement and the measures do not match. The requirement is to "manage". Sometimes a well managed environment can still fail. The measures are "failures". If the measures are failures and any failure is a violation, then, the requirement should be to "prevent" not to "manage". Staff's proposed VSLs highlight this inconsistency. The 100% compliance requirement, as opposed to a statistical measure such as 99.99% availability, and Measures that say that any Sustained Outage is a possible violation unless proven otherwise leads us to extreme methods of management, such as possibly having video cameras monitoring the ROW at all times. Is this what the Drafting Team intends? FMPA would suggest that if perfromance is the real purpose of these standards, then "manage" is the wrong requirement, and "prevent" is a more appropriate term. If prevention is the real requirement, then we need a paradigm of "innocent until proven guilty" and any unknown source of a sustatined outage is assumed not to be a vioaltion until proven guilty, and, 100% is not a reasonable target, 99.99% or similar umber over a number of years (e.g., so many years rolling average) is a more reasonable target. Do we require 100% compliance with vehicle brakes (ala Toyota Prius)? Or tire blowouts (ala Ford Explorer)? With associated fines? If we did, the auto manufacturers would probably not offer cars to the American market due to too much risk and liability. TQM (total

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				qulaity management) processes, such as six sigma (i.e., 6 standard deviations) do not mandate 100% reliability becuase 100% reliability is too expensive. Rather, we need a conservative target where outliers beyond regional management controls do not result in huge fines and huge liability (especially in consideration with FERC's proposed Policy Statement on Sanctions) R4 "Each Transmission Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated transmission line when qualified personnel confirm the existence of a vegetation condition that is likely to cause a Fault at any moment" How is R4 even measureble? How are we to measure how someone would determine "the existence of a vegetation condition that is likely to cause a Fault at any moment"? Having the requirement in the standard may have the unintended consequence of reverse psychology e,g., not notifying may not even open up the question of compliance with this requirement. However, if a sustained outage were to occur as a result violating R1 or R2, would this requirement necessitate launching an investigation of whether or not "qualified" personnel would have seen a problem. I see this requirement as fraught with difficulties. Would this requirement essentially require a procedure for "detecting" in R3 in addition to "preventing" If 100% compliance is the chosen method for R1 and R2, why is R4 (and R5 for that matter) even needed? Obviously, if there is an impending failure that would cause a vioaltion of R1 and R2, then there is obviously incentive to report it to the System Operator. R7 "Each Transmission Owner shall complete the work in an annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk of a vegetation encroachment. Examples of reasons for modification to annual plan may include ...." The first sentence should not include the phrase "to ensure no vegetation encroachments occur" since the requirement is to do the work in the work plan. The added phrase sinply adds ambiguity, e.g., if there is an encroashment, is R7 violated since it does not meet hte "unsure" phrase in addition to R1 and R2? Periodic Data Submittals Due to R1 and R2, this is really a self-certification process because essentially only violations to R1 and R2 as curently drafted would be reported. So, this section should be deleted in favor of a CMEP process for periodic self-certifications on the standard.

Response: Thank you for your comments. Based on recommendations, the language in M1/M2 has been modified. Proof that an outage was vegetation related will be determined through the investigation of the outage. If clear evidence as determined by the Transmission Owner exists, the entity would then self-report. R4 exists to ensure that "expeditious communication between the Transmission Owner **and proper operating personnel when a critical situation is confirmed." This situation does not necessarily imply a violation of R1 and R2. The intent is to minimize the risk of an event that could cause a cascading event. Regarding the inclusion of the phrase "to ensure no vegetation encroachments occur" in R7, the intent of the SDT is to include language to indicate who should do what when, where, and why as part of the Results Based Standards format.**

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Silvia P Mitchell	Florida Power & Light Co.	6	Negative	NextEra Energy, Inc believes that this standard is a step in the right direction; however, it is not ready for ballot. The posted version uses the Measures and Compliance sections to define and interpret Requirements. The Requirements should stand by themselves. This version of the standard lumps grow-in violations with fall-in and blow-in violations. Fall-in and grow-in violations have no correlation to the cascading events stated in the purpose. We believe it needs more work before ballot approval.
Response: The SDT thanks you for your comment. The SDT modified R1 and R2 to incorporate the severity into the requirement. This will allow for a graded VSL. The team also modified the measure so that it does not qualify the requirement. These changes should resolve your issues.				
Larry E Watt	Lakeland Electric	1	Negative	o The draft standard requires perfection, which is an unreasonable performance metric o The standard is prone to arguments of whether or not an outage was caused by vegetation encroachment in the current "guilty until proven innocent" paradigm we are currently in o Are the requirements measurable (e.g., R4 and R5)? o Goals of requirements should not be mixed with the requirement itself. Goals add ambiguity of what is being measured, the requirement (e.g., "complete the work plan" in R7) or the goal (e.g., "ensure no vegetation encroachment occurs"). o Periodic data submittals as written are really periodic self-certifications and ought to be named such, or 100% compliance reduced to a more reasonable target
Response: The SDT thanks you for your comments. The SDT recognizes that the Standard as written is zero tolerance and believes it is compelled to write it that way. FERC staff and NERC assert that a revised standard cannot result in less reliability than the one it replaces, and, their belief is the current Standard is zero tolerance. The SDT believes that R4 and R5 are measurable as described. The RBS process is essentially "Who should perform What actions under What conditions." Thus the Goals are included. Finally, FERC would prefer to have early warnings that reliability is at risk, rather than wait for that indication when the next blackout occurs. Hopefully, periodic data offers that early warning detection.				
David H. Boguslawski	Northeast Utilities	1	Negative	Our main issue is with the change in the Active ROW definition. The recent addition of a centerline distance to edge of Active ROW is not acceptable as it does not take into consideration the construction of the line (e.g., mono-pole vs. H-frame). For mono-pole construction, the use of the Table 3 centerline distance could result in additional clearing of the forested edge on existing ROWs with no value added to system reliability. Instead of using the term "Centerline" as referenced on Table 3, the use of "outer phase" or "phase closest to tree line" would be more appropriate.
Response: The SDT thanks you for your response. Due to many commenters having issues with trying to define a "minimum" width, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.				
Mace Hunter	Lakeland Electric	3	Negative	Perfection is not a reasionable performance metric
Response: The SDT thanks you for your comment. The SDT recognizes that the Standard as written is zero tolerance and believes it is compelled to				

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<tr><td>Brenda L Truhe</td><td>PPL Electric Utilities Corp.</td><td>1</td><td>Negative</td><td>Please refer to the Comments submitted by Earl Burnside, PPL Electric Utilities, via the NERC Comment Form on 7/16/2010.</td></tr>
<tr><td colspan="5">Response: See responses to Earl Burnside, PPL Electric Utilities.</td></tr>
<tr><td>Mark A. Heimbach</td><td>PPL Generation LLC</td><td>5</td><td>Negative</td><td>Please refer to the comments submitted by Earl Burnside, PPL Electric Utilities, on 7/16/10.</td></tr>
<tr><td colspan="5">Response: See responses to Earl Burnside, PPL Electric Utilities.</td></tr>
<tr><td>John C. Collins</td><td>Platte River Power Authority</td><td>1</td><td>Negative</td><td rowspan="2">PRPA appreciates the SDT’s reliability objective through a defense-in-depth strategy and the improvements made to the standard since its last posting. However, several issues will cause us to vote negative. Our first concern is that a violation caused by an encroachment into the Minimum Vegetation Clearance Distance as shown in Table 2, observed in real time, absent a Sustained Outage does not improve reliability of the BES. Instead we believe the clearances to be achieved in the current version of the standard under R1.2. are a better measurement of expectations because they establish a clearance to be achieved at the time of work. Our next concern is with the ambiguity of the wording “without any intentional time delay” in R4 of the proposed standard. For instance, would a call from the lineworkers to his/her supervisor prior to a call to the control center constitute an intentional delay or would that be part of the confirmation process? We also question what constitutes qualified personnel in R4. Does this imply that R1.3. in the current standard requiring appropriate qualifications and training is still applicable although not implicated stated and will those qualifications be audited as they are now? Our last concern is that landowners will intentionally constrain and delay work through court orders pointing to our Federal requirement to take corrective action. We know this isn’t the intent of the requirement but have some concern that it might be misinterpreted by landowners as their defense to force us to investigate or perform alternate work methodology.</td></tr>
<tr><td>Terry L Baker</td><td>Platte River Power Authority</td><td>3</td><td>Negative</td></tr>
<tr><td colspan="5">Response: Thank you for your comments. While the SDT has struggled with the issue of encroachments into the MVCD being a violation, the fact that a TO would allow vegetation to approach, let alone encroach the MVCD indicates a serious flaw in the TO’s vegetation management program and its application. The TO has every right and should under the proposed standard establish clearance distances at the time of work (Clearance 1 in FAC-003-1) to allow for growth. With regard to Clearance 1 of version 1 the SDT considered it a “fill in the blank” requirement. Thus, including it in version 2 was considered prescriptive and unnecessary.
The time required by the TO to report an issue is subject to many variables such as available communication for the area which could be a hike-in location with no radio or cell phone coverage. For this reason it is difficult to establish a time period which would fairly apply to all TO’s. Thus, the SDT has taken the approach which does create some subjectivity. With regard to your question regarding a call from a line worker to a supervisor being viewed as intentional delay, we would need to know if this call is part of your process for reporting imminent threats. If your process has this</td></tr>
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check point or the flexibility for the lone worker to call a supervisor, then the SDT would not view this as an intentional delay. **Qualified personnel is a function of many variables such as the size of the TO's system, type and density of vegetation, access and complexity of the vegetation management program. All these factors will drive the qualification requirements as defined by the TO for personnel developing and administering the program. For instance a TO with little vegetation on its ROW may require little in the way of knowledge and methodologies in meeting this standard while those TO's with extensive and significant vegetation must use varied methodologies to control vegetation on its ROW such as mechanical control, manual control, herbicides and so on. Thus, the standard leaves it to the TO to define what defines qualified personnel. Refer to the reference document for more guidance.** **As you point out, it is not the intent of this standard to cause the landowner to intentionally constrain and delay work. But, it is also not the intent of the standard to drive the land owner or land manager to any other behaviors. It is the TO's responsibility to manage relationships and develop methodologies within and to the full extent of the easement or permit language. Requirement R5 deals with this issue and additional clarification is given in the Rationale for this requirement.**				
David Schumann	Florida Municipal Power Agency	5	Negative	R1 & R2 My biggest problem is with R1 and R2 "Each Transmission Owner shall manage vegetation to prevent encroachment that could result in a Sustained Outage of applicable lines .... Types of encroachment include: 1. An encroachment into the Minimum Vegetation Clearance Distance (MVCD) as shown in Table 2, observed in real time, absent a Sustained Outage, 2. An encroachment due to a fall-in from inside the active transmission line ROW that caused a vegetation-related Sustained Outage, 3. An encroachment due to blowing together of applicable lines and vegetation located inside the active transmission line ROW that caused a vegetation-related Sustained Outage, 4. An encroachment due to a grow-in that caused a vegetation-related Sustained Outage" One fundamental problem with all the standards is the demand for no faults, no errors, 100% compliance. Requirements 1 and 2 basically say that any vegetation related outage, except for blow ins from outside the ROW, is a violation. A few issues with this: How would we "prove" that an outage is vegetation related or not, and if vegetation related, where the vegetation came from? Would this be a "guilty until proven innocent" paradigm, e.g., if we don't know what the cause was, then we assume guilty, or an "innocent until proven guilty" paradigm, e.g., clear evidence is needed to prove guilt? Current compliance monitoring and enforcement methods are to assume guilt with the need for clear evidence of innocence until a hearing is requested, at which point the paradigm is reversed. If this is how we expect it to happen? I could see a large number of "Possible" and "Alleged" violations where the cause of the sustained outage or the source of the vegetation is unknown, and a large number of hearings, unless we begin with the paradigm with "innocent until proven guilty", which is not the approach monitoring and enforcement take currently. The requirement and the measures do not match. The requirement is to "manage". Sometimes a well managed environment can still fail. The measures are "failures". If the measures are failures and any failure is a violation, then, the requirement should be to "prevent" not to "manage". Staff's proposed VSLs highlight this inconsistency. The 100% compliance requirement, as opposed to a statistical measure such

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Voter	Entity	Segment	Vote	Comment
				encroashment, is R7 violated since it does not meet hte "unsure" phrase in addition to R1 and R2? Periodic Data Submittals Due to R1 and R2, this is really a self-certification process because essentially only violations to R1 and R2 as curently drafted would be reported. So, this section should be deleted in favor of a CMEP process for periodic self-certifications on the standard.
Response: Thank you for your comments. Your concern with respect to the cause of an outage is well-taken. As you know, transmission systems are subject to many different influences which can cause a sustained outage. Among those causes is the encroachment of vegetation into the MVCD which could be due to improper maintenance of vegetation on one's ROW. However, there are many other causes which can initiate a sustained outage. A TO usually investigate a sustained outage in the field to determine, if possible, the cause of the outage. Typically, a vegetation caused outage will leave some evidence of the flashover such as burn marks on the conductor together with burned portions of the vegetation. Indications may be found to explain the outage due to other causes but in some cases the cause cannot be determined and the line is successfully re-energized without ever knowing what caused the outage. It is incumbent upon the TO to self- report those outages obviously caused by vegetation but unexplained outages would not fall under this requirement or standard. **The SDT believes the language in the requirement matches the language in the measure such as in R1 "Each Transmission Owner shall manage vegetation to prevent encroachment…" and in M1 "Each Transmission Owner has evidence that it managed vegetation to prevent encroachment…". Your suggestion of using statistical analysis may work well with large TO's with many miles of transmission ROW to spread small numbers of outages over but would disadvantage the small TO with significantly fewer miles of line. Only one outage on its system could result in huge fines.** **The SDT believes R4 is a valid "Risk Based Requirement" giving guidance to industry on what to do upon discovery of an encroachment into the MVCD in order to prevent a sustained outage. The key is for the TO to communicate with the appropriate switching authority and the measure is evidence of such communication when a potential vegetation imminent threat occurs. R7, as documented in the Rationale, "…sets the expectation that the work identified in the annual work plan will be completed as planned". Documentation of the work completed (and any necessary modifications) as written together with the lack of of a violation to either Requirement 1 or Requirement 2 is the overall reliability goal. The metric for the work plan is the percentage of the plan complete. The lack of a violation of R1 or R2 is the outcome of the ideal work plan. It is the responsibility of the TO to manage the quality of the work plan and its associated modifications to mitigate the risk of a violation of R1 or R2. With Version 2, an outage is now clearly a violation of R1 and R2 and should not be linked to a failure of the work plan. The measure for the work plan is the percentage of the completed as planned and we do not need to be subjectively trying to evaluate the quality of the TOs plan with this measure. With regard to the "Periodic Reporting Data Submittal" section the SDT agrees with reporting outage to the Regional Entity on a quarterly basis. In addition regulatory authorities are looking for leading reliability indicators which will support quarterly reporting rather than an annual self-certification.**				
Kenneth Simmons	Gainesville Regional Utilities	3	Negative	R4 The use of intentional time delay is a qualitative attribute and not a quantitative measure. How does one judge intentional versus non-intentional on a qualitative basis; subjective at best leading to many arguments between auditor and auditee?
Response: Thank you for your comment. We agree the time required by the TO to report an issue is subject to many variables such as available communication for the area which could be a hike-in location with no radio or cell phone coverage. For this reason it is difficult to establish a time period which would fairly apply to all TO's. Thus, the SDT has taken the approach which does create some subjectivity. The key is for the TO to have an imminent threat process that includes the communication with the appropriate switching authority. The measure for compliance will be evidence such as written and taped radio/telephone logs maintained by the control center; written daily diaries kept by the patrollers and inspectors could also be used for this purpose.				

Voter	Entity	Segment	Vote	Comment
Luther E. Fair	Gainesville Regional Utilities	1	Negative	R4: The use of intentional time delay is a qualitative attribute and not a quantitative measure. It will lead to endless arguments over intentional versus non-intentional. R4 should be: Each Transmission Owner shall notify the control center holding switching authority for the associated transmission line no more than 6 hours of a qualified personnel confirm the existence of a vegetation condition that is likely to cause a Fault at any moment. R7: R7, as proposed, requires a VMP to be completed to ensure no encroachment occurs. The Supplemental Reference for R7 does not describe the requirement of the annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. The Reference states the requirement is established to diminish the risk of encroachment; very different from ensuring no encroachment. In the reference for R7 the word "ensure" is only used to describe that flexibility in the VMP is allowed to ensure the reliability of the Transmission System. The above comments are from United Illuminating and shared by myself. Earl
Response: Thank you for your comments. We agree the time required by the TO to report an issue is subject to many variables such as available communication for the area which could be a hike-in location with no radio or cell phone coverage. For this reason it is difficult to establish a time period which would fairly apply to all TO's. Thus, the SDT has taken the approach which does create some subjectivity. The key is for the TO to have a imminent threat process that includes the communication with the appropriate switching authority. The measure for compliance will be evidence such as written and taped radio/telephone logs maintained by the control center; written daily diaries kept by the patrollers and inspectors could also be used for this purpose. **R7, as documented in the Rationale, "…sets the expectation that the work identified in the annual work plan will be compiled as planned". Documentation of the work completed (and any necessary modifications) as written together with the lack of of a violation to either Requirement 1 or Requirement 2 is the overall reliability goal. The metric for the work plan is the percentage of the plan complete. The lack of a violation of R1 or R2 is the outcome of the ideal work plan. It is the responsibility of the TO to manage the quality of the work plan and its associated modifications to mitigate the risk of a violation of R1 or R2. With Version 2, an outage is now clearly a violation of R1 and R2 and should not be linked to a failure of the work plan. The measure for the work plan is the percentage of the completed as planned and we do not need to be subjectively trying to evaluate the quality of the TOs plan with this measure.**				
David A. Lapinski	Consumers Energy	3	Negative	Table 3 does not adequately address ROW width requirements based on the type of construction used for structures, especially for the two lower voltage classes, 69-138kV and

Voter	Entity	Segment	Vote	Comment
David Frank Ronk	Consumers Energy	4	Negative	139-230 kV. Lines constructed on H-Frame structures have a much wider footprint across the ROW than do single pole construction and most steel tower construction types. The minimum ROW width listed in Table 3 for a 138 kV line constructed on a wooden H-Frame may put the outside conductor within MVCD under windy conditions due to wind displacement of conductors and trees. Consumers Energy recommends that Table 3 be modified to describe the minimum distance in the table is the vertical plane of the outside conductor to the edge of the active transmission ROW and therefore independent of the width of the structure construction type. MI and M2 fail to provide examples of acceptable forms of evidence to prove that a Transmission Owner actively managed vegetation to prevent encroachment into the MVCD. The Measures should require proof of active ROW clearing activity in accordance with the transmission vegetation management plan, such as invoicing or crew field reports or vegetation inspection data from the annual vegetation inspection R3 avoids defining a minimum clearance specification and is not practical. As written, this would require each Transmission Owner to define and document the procedures, processes or specification by individual span for every line owned or operated by the Transmission Owner. Each span varies in length and profile and a single line may have several different conductor types with different load ratings. Line loadings will vary along the line based on substation taps, etc. The dynamics described in the language could only be done on an individual span basis to be reasonably accurate. This is not practical from a planning standpoint or from a standpoint of implementing clearing work in the field.
Response: The SDT thanks you for your comments. **1) Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** **2) M1 and M2 do provide samples of acceptable forms of evidence. The examples you have provided in your comment would also be acceptable forms of evidence. The SDT recognizes that there are many acceptable forms of evidence and only included three specific examples in both Measures M1 and M2 utilizing the phrase 'may include' so that the list is not limited to the samples provided.** **R3 specifically states that the TO shall prevent encroachment into the MVCD which is a defined minimum clearance distance, contrary to your comment. To prevent a Sustained Outage, each TO must recognize that each transmission line is unique and establish a general plan that encompasses each scenario. In their procedures or processes or specifications, the TO shall establish a maintenance strategy that ensures vegetation will never violate the MVCD. This strategy should take into consideration the dynamics of vegetation growth and conductor movement as explained in the Guidelines and Technical Basis section of the Standard (Page 21). This strategy does not necessarily require a span by span analysis.**				
Bernard Pelletier	Hydro-Quebec TransEnergie	1	Negative	Table 3 is not acceptable for HQTE. In many places, our standard of design allow us a ROW width much narrower. We think that Table 3 should cover only the lines operated at 200 kV or higher. Finally, the Table 3 should not be a requirement of the FAC-003-2.
Response: Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.				

Voter	Entity	Segment	Vote	Comment
Stan T. Rzad	Keys Energy Services	1	Negative	The draft standard requires perfection, which is an unreasonable performance metric The standard is prone to arguments of whether or not an outage was caused by vegetation encroachment in the current "guilty until proven innocent" paradigm we are currently in Are the requirements measurable (e.g., R4 and R5)? Goals of requirements should not be mixed with the requirement itself. Goals add ambiguity of what is being measured, the requirement (e.g., "complete the work plan" in R7) or the goal (e.g., "ensure no vegetation encroachment occurs"). Periodic data submittals as written are really periodic self-certifications and ought to be named such, or 100% compliance reduced to a more reasonable target
Response: The SDT thanks you for your comments. 1. **The SDT recognizes that the Standard as written is zero tolerance and believes it is compelled to write it that way because FERC staff and NERC assert that a revised standard cannot result in less reliability than the one it replaces and their belief is the current Standard is zero tolerance.** 2. **As explained in M1 and M2, only real time observations confirmed by a qualified person would constitute an encroachment. There may be some difficulty proving whether or not an outage was caused by vegetation but, if an investigation at any time reveals definitive evidence of a vegetation contact as determined by the Transmission Owner, this would be the proof.** 3. **The SDT believes that R4 and R5 are measurable as described in the Draft but would gladly accept suggestions for revision in future postings. The RBS process essentially is “Who should do what, under what conditions, when, and why?” Thus the Goals are included. Finally, FERC staff has stated that they would prefer to have early warnings that reliability is at risk rather than wait for that indication when the next blackout occurs. Thus, periodic data offers that early warning detection.** **Periodic data submittal is not only restricted to self-certifications so the SDT has chosen to keep the language the same as currently drafted.**				
Thomas W. Richards	Fort Pierce Utilities Authority	4	Negative	The draft standard requires perfection, which is an unreasonable performance metric. Also, the standard is prone to arguments of whether or not an outage was caused by vegetation encroachment in the current "guilty until proven innocent" paradigm we are currently in. I have the question about the ability to measure compliance with R4 and R5 as written. Goals of requirements should not be mixed with the requirement itself. Goals add ambiguity of what is being measured, the requirement (e.g., "complete the work plan" in R7) or the goal (e.g., "ensure no vegetation encroachment occurs"). Periodic data submittals as written are really periodic self-certifications and ought to be named such, or 100% compliance reduced to a more reasonable target
Response: The SDT thanks you for your comments. 1. **The SDT recognizes that the Standard as written is zero tolerance and believes it is compelled to write it that way because FERC staff and NERC assert that a revised standard cannot result in less reliability than the one it replaces and their belief is the current Standard is zero tolerance.** 2. **As explained in M1 and M2, only real time observations confirmed by a qualified person would constitute an encroachment. There may be**				

Voter	Entity	Segment	Vote	Comment
some difficulty proving whether or not an outage was caused by vegetation but, if an investigation at any time reveals definitive evidence of a vegetation contact as determined by the Transmission Owner, this would be the proof. **3. The SDT believes that R4 and R5 are measurable as described in the Draft but would gladly accept suggestions for revision in future postings. The RBS process essentially is "Who should do what, under what conditions, when, and why?" Thus the Goals are included. Finally, FERC staff has stated that they would prefer to have early warnings that reliability is at risk rather than wait for that indication when the next blackout occurs. Thus, periodic data offers that early warning detection.** **4. Periodic data submittal is not only restricted to self-certifications so the SDT has chosen to keep the language the same as currently drafted.**				
Thomas E Washburn	Florida Municipal Power Pool	6	Negative	The draft standard requires perfection, which is an unreasonable performance metric The standard is prone to arguments of whether or not an outage was caused by vegetation encroachment in the current "guilty until proven innocent" paradigm we are currently in Are the requirements measurable (e.g., R4 and R5)? Goals of requirements should not be mixed with the requirement itself. Goals add ambiguity of what is being measured, the requirement (e.g., "complete the work plan" in R7) or the goal (e.g., "ensure no vegetation encroachment occurs"). Periodic data submittals as written are really periodic self-certifications and ought to be named such, or 100% compliance reduced to a more reasonable target
Response: The SDT thanks you for your comments. **1. The SDT recognizes that the Standard as written is zero tolerance and believes it is compelled to write it that way because FERC staff and NERC assert that a revised standard cannot result in less reliability than the one it replaces and their belief is the current Standard is zero tolerance.** **2. As explained in M1 and M2, only real time observations confirmed by a qualified person would constitute an encroachment. There may be some difficulty proving whether or not an outage was caused by vegetation but, if an investigation at any time reveals definitive evidence of a vegetation contact as determined by the Transmission Owner, this would be the proof.** **3. The SDT believes that R4 and R5 are measurable as described in the Draft but would gladly accept suggestions for revision in future postings. The RBS process essentially is "Who should do what, under what conditions, when, and why?" Thus the Goals are included. Finally, FERC staff has stated that they would prefer to have early warnings that reliability is at risk rather than wait for that indication when the next blackout occurs. Thus, periodic data offers that early warning detection.** **4. Periodic data submittal is not only restricted to self-certifications so the SDT has chosen to keep the language the same as currently drafted.**				
Laurie Williams	Public Service Company of New Mexico	1	Negative	The draft standard suggests that the expectation for compliance is perfection or zero encroachments at all times. It would be cost prohibitive to maintain the system under those rules and should be amended to include a provision to account this issue - particularly for small utilities that operate over very large geographic region with sparsely distributed

Voter	Entity	Segment	Vote	Comment
				transmission assets.
Response: The SDT thanks you for your comments. The SDT recognizes that the Standard as written is zero tolerance and believes it is compelled to write it that way because FERC staff and NERC assert that a revised standard cannot result in less reliability than the one it replaces and their belief is the current Standard is zero tolerance.				
Matt Culverhouse	City of Bartow, Florida	3	Negative	The proposed standard requires perfection which we feel is unreasonable.
Response: The SDT thanks you for your comments. The SDT recognizes that the Standard as written is zero tolerance and believes it is compelled to write it that way because FERC staff and NERC assert that a revised standard cannot result in less reliability than the one it replaces and their belief is the current Standard is zero tolerance.				
Robert D Smith	Arizona Public Service Co.	1	Negative	The reasons for APS to vote NO. The standard drafting team went above and beyond and changed the whole standard and didn't address all of FERC's concerns. (0) The minimum clearances must be sufficient to avoid any sustained vegetation-related outages for all applicable conditions. (1) The team eliminated clearance 1 requirement which isn't addressed in this revision according to FERC's request. FERC wanted this requirement to be standardized. Elimination of clearance 1 doesn't give utilities leverage when dealing with federal land agencies. They are making decisions without any education or knowledge on UVM activities which affect transmission reliability. There needs to be a clearance 1 requirement in the standard. If utilities are required to follow this standard it gives them leverage with dealing with these federal land agencies. (2) They removed ANSI-A300 from the standard. It was a footnote but should be part of the standard. Utilities should be held to following ANSI A-300 standards and BMP's for best management practices. By following these standards there wouldn't be a need for the FAC-003 standard. (3) Removal of 'fill in the blank' components where the Transmission Owner determines the requirement with no limits or direction. Examples include and "personnel requirements" in version 1. The SDT removed this requirement from the current version. ? Personnel qualifications should be a requirement. There are certification programs through the International Society of Arboriculture that certify a minimum level of competence to manage a vegetation management program. This also requires ongoing training and education to keep up with the latest technologies on UVM. ? There are other standards that require qualifications and training.

Voter	Entity	Segment	Vote	Comment
				(4) Application of new NERC Drafting Team Guidelines (DTG) to the standard. Examples include the replacement of the current compliance section with Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) as referenced in the Sanction Guidelines. Additionally, documentation and implementation elements are separated into different requirements in the proposed standard as required by the DTG. (5) This requirement in regard to outages from within the ROW was diluted to remove accountability from maintaining the full width of utilities easement. An outage is an outage from a grow-in or from a blow in. If a utility has rights to maintain vegetation there shouldn't be any outages due to vegetation from blowing into the conductors. The active ROW should be wide enough to prevent these types of outages. o Address the applicability and appropriateness of IEEE 516 in determining clearance distances. ? No issues with the change to Gallet equation. ? The issue is each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-Time observations of any MVCD encroachments. ? (6) A real-time observation doesn't take into account all rated conditions and the time the recording was made. Conditions change and if load is increased those previous observations could be potential outages. I would assume our Energy Control people would want to be confident there wouldn't be any tree-related issues if load had to be increased. ? There is technology available with LIDAR to simulate all-rated conditions, contour and tree height to remove these potential trees hazards before an outage occurs. o Address applicability of this standard to sub 200kV lines that could place the grid at an unacceptable risk of instability, separation, or cascading failures. ? (7)The utilities should be required to inspect all the lines annually. The change isn't what FERC requested. o Address applicability to federal lands. ?

Voter	Entity	Segment	Vote	Comment
				(8)There should be a footnote that if federal or state agencies fail to approve annual work plans within 90 days of submittal the utility will not be held accountable for not completing its annual work plan or taking into account the time it takes to get approval. We have land agencies that give us approvals within 2 weeks and others that have taken over a year. Utilities are at their mercy on the approval process. If there is turn-over in the land agency the approval process changes again and it is impossible to determine the anticipated timeline by state, tribal and federal agencies. ? The SDT didn't address the need for FERC oversight on federal lands as the example listed above. Agencies are not qualified to make decisions on utility vegetation management and can change utilities TVMP. (9)Finally the current version FAC-003-1 is performing and there is no need to make the change.

Response: Thank you for your comments.

(0)If vegetation is maintained as required in this draft of the standard in requirements R1 and R2, then no vegetation related sustained outages, caused by vegetation from within the ROW, within the control of the TO can occur.

(1) Clearance 1 was a fill-in the blank requirement and did not provide the TO any new easement rights, or land permit rights across any lands whether those land be privately owned or publicly owned; therefore Clearance 1 remains removed from this draft. Furthermore, the relevance of Clearance 1 depends on several other factors such as length of maintenance cycles, inspection frequency and growth rates. R3 is now used as a more comprehensive method to address these concerns in lieu of a Clearance 1 requirement.

(2) In order to meet the SAR FAC-003 is required. ANSI-A300 is not sufficient to meet the SAR requirements and contains many elements that do not need to be related to transmission system electrical reliability.

(3)The SDT suggests that the submittal of a NERC SAR on the PER standards be considered to address any proposed personnel qualifications, certifications or training issues.

(4) The SDT is following NERC guidelines as they understand them.

(5) The SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way; subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed. Outages arising from vegetation from outside the ROW are not violations of the standard. The SDT had determined this to be the most appropriate assignment of an area of maintenance responsibility considering the numerous variations in easements and permit rights across North America.

(6)The Standard requires the maintenance to be performed such that loading to Rating and Rated Conditions, and the dynamics of sag and sway are are taken into consideration, additionally any real time observations of encroachments into the MVCD are to be reported as violations of the standard. The SDT does not see the need to be prescriptive as to the technology or tools the TO used to be compliant with the Standard, but is confident that if the vegetation in maintained such that no encroachments are ever observed, and no outages are ever occur, then the reliability purpose of the standard will be fully accomplished. Furthermore, the results from a LIDAR survey are temporal in nature. Any program relying on LIDAR would incur a substantial cost with a long term commitment that may not be justified for many Transmission Owners.

(7) FERC requested a defined period for inspection. The SDT agrees with you that annual inspection is required. Therefore the SDT has made annual inspections a Requirement of this Standard. As to all lines versus applicable lines, FERC has accepted the 200 kV bright line for this standard. They did order the SDT to ensure that no sub-200 kV lines that are important to the Bulk Electric System are missing from the Applicability of the standard.

Voter	Entity	Segment	Vote	Comment
The SDT has incorporated a FERC accepted test (as found in the referenced Standard) to make sure no such important lines are missing. **(8)The SDT agrees that erroneous obstacles to compliance with the standard should be addressed. However, they cannot be resolved in this forum, or through language inserted in this standard. This Standard places requirements on the Transmission Owners, not on landowners. There is no legal mechanism for this Standard to take rights from property owners and assign them to the Transmission Owner.** **(9)The SDT is changing the Standard in responds to the SAR. The success of the existing standard will be preserved and enhanced with this revision.**				
Paul Shipps	Lakeland Electric	6	Negative	The standard is prone to arguments of whether or not an outage was caused by vegetation encroachment.
Response: Thank you for your comments. **The Compliance Section of the Standard provides the direction under which the Compliance Monitoring and Enforcement Processes and the TOs must report compliance to this standard. All possible violations need adequate investigation to determine if a vegetation related outage occurred. The SDT recognizes that such determination are often very challenging, however more prescriptive language on investigations has been seen as necessary by the SDT and would not contribute to increased reliability. NERC also requires the TOs to document all outages and their related causes in the TADS system.**				
Daniel Brotzman	Commonwealth Edison Co.	1	Negative	The term “Centerline of the Circuit” in Table 3 is not defined. Until it is defined, there is no way to know if the standard is technically reasonable or whether existing circuits would be in violation of the standard and unable to operate. In addition, it is unclear what types of construction and span lengths were used to develop the distances for active right-of-way widths in Table 3. Furthermore, it is not clear whether Table 3 contains requirements against which compliance will be measured or best practice guidelines. Footnote 2, in the background section, compounds this ambiguity. In short, the lack of a definition for “Centerline” combined with Footnote 2 and Table 3 make this draft unclear and unenforceable. Exelon does not necessarily have easement widths for all transmission lines that equal those defined in Table 3 of this draft; This may require the acquisition of additional easements, if even possible.
Response: Thank you for your comments. **In response to your comments and similar comments to yours, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.**				
Alan Gale	City of Tallahassee	5	Negative	There is still confusion in R7. If I do not complete the work plan, but do not have any encroachments, have I violated R7? As worded I would argue no. I do not believe the ambiguity can remain in the standard. If the goal is to complete the work plan (as modified) leave out the "to ensure no vegetation encroachments..." If the goal is to have no encroachments, do not rely on a work plan to exist. Make the standard "Each TO shall ensure no vegetation encroachments occur." I do agree with the performance based

Voter	Entity	Segment	Vote	Comment
				approach and format.
Response: Thank you for your comments. The SDT considered your response but feels that when one considers all the text in R7, M7, the Rationale and the related VSL, along with the text in the Guidelines and Technical Basis, it is sufficiently clear that this requirement is about the completion of the work plan.				
Roger C Zaklukiewicz		8	Negative	To maintain reliability, the minimum distance from a conductor to tall vegetation should be measured from the conductor nearest the edge of the cleared ROW to the edge of the ROW and not from the center line of the transmission structure. The type of transmission line configuration, horizontal or vertical - monopole versus H-Frame versus lattice-structure versus a V-Guided structure will influence how effective a transmission circuit's performance or reliability is when the measurement is made from the centerline of the transmission line. Table 3 should be modified to reflect this concern to ensure the reliability of the EPS.
Response: In response to your comments and similar comments to yours, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way; subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.				
Brian Evans-Mongeon	Utility Services, Inc.	8	Negative	Utility Services supports the NPCC position on the fixes to this standard proposal.
Response: Thank you for your comments. Please refer to our response to NPCC.				
John K Loftis	Dominion Virginia Power	1	Negative	We do not agree with replacing the term “Active Transmission Line Right of Way” with footnote 2. Our objection is around the distances proposed in Table 3. Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW may not be consistent with the centerline distances cleared and maintained by the TO. For example, a TO maintaining 75’ from centerline for a 500kV circuit would be required to clear and maintain an additional 12.5’ to meet the proposed standard’s requirement. We suggest either allowing individual TOs to maintain active ROW widths consistent with their normal clearing/maintenance practices, going back to Draft 3’s definition of Active Transmission Line Right-of-Way, or changing the footnote in Draft 4 to read: A strip or corridor of land
Michael F Gildea	Dominion Resources Services	3	Negative	
Mike Garton	Dominion Resources, Inc.	5	Negative	

Voter	Entity	Segment	Vote	Comment
Louis S Slade	Dominion Resources, Inc.	6	Negative	that is occupied by active transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities. However, the portion of the ROW that has been cleared must at least meet design clearance requirements such as National Electric Safety Code or other design criteria, for the reliable operation of active facilities.
Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way; subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.				
Ronald L Donahey	Tampa Electric Co.	3	Negative	We have concern with the “Minimum Distances” as listed in Table 3. What analytical methodology, criteria and rationale was utilized to determine each recommended distance? In addition, we have concerns regarding the change to a pre-determined distance. This seems to be a major shift from the vegetation to conductor methodology employed previously and throughout this standard? NERC/FERC must recognize that while protecting and securing grid reliability, each utility must also balance the environmental, political, customer and economic issues and impacts which will occur with the implementation of the Table 3 clearances. We question whether this is the most responsible action to take given the current state of the economy as well as the environmental and political sensitivity impacts which will result. Tampa Electric questions whether Table 3 will improve System reliability. Since the inception of standard FAC-003-1 Tampa Electric has not had a Category 1 or Category 2 outage on our 230kV Transmission System. We don’t believe that the changes proposed to table 3 will improve overall service reliability. It is Tampa Electric’s opinion that each utility should define the width of its own Active Transmission line ROW. However, if such a table is to be utilized, Tampa Electric recommends the following changes or adjustments to Table 3. 1. Expand the table to account for the various types of Transmission construction; i.e. vertical versus horizontal conductor configurations. 2. Use a distance from the outermost conductor, not the centerline. This will account for construction type and better achieve a consistent clearance from conductors. 3. We recommend reducing the distances in Table 3 by 12.5 feet for each voltage category. 4. Specify whether the voltage is based upon the design or operating voltage. 5. Reformat the voltage ranges to 100kV - 200kV, 200kV - 300kV, 300kV - 400kV, etc. as an example; this would create a more appropriate range of voltages and clearance distances. The reformatted voltage ranges eliminate confusion. For example, under the current proposal it is unclear in which category a nominal 230kV line should be since sometimes such a line can operate at up to 232kV during low-load conditions.
Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.				

Voter	Entity	Segment	Vote	Comment
Joseph O'Brien	Northern Indiana Public Service Co.	6	Negative	While there are some enhancements to the organization and content of the standard such as the addition of the Guidelines and Technical Basis section, clarification of what constitutes evidence of compliance, and tailoring of VSL severity levels for the requirements based on the risk each poses to the likelihood of contributing to a cascade, too many elements present in FAC-003-1 and which are vital to preventing vegetation caused outages and maximizing system reliability, have been eliminated from FAC-003-2. Specifically, the elimination of concrete, declared and audited clearance standards between vegetation and conductors (the existing Clearance 1 and Clearance 2 (R1.2)) Requirements) in the revised standard is a major defect that will decrease system reliability. It has been indispensable for NIPSCO when communicating with stake holders (governments, interest groups, land owners, the public, etc.) to point to these clearance standards to give credibility and support to the kind of tree removal and trimming that is necessary to achieve the stated objective of zero preventable tree caused outages. Without these declared clearance standards in the NERC standard, utility vegetation managers will constantly be challenged by stake holders to show them that such work is required rather than an elective choice on the utility's part. One of the key lessons learned from the 2003 blackout and First Energy's overgrown ROW tree problem was that individual land owners, local governments, and interest groups will exert pressure on the utility to only do the minimum amount of vegetation management. Without external and enforceable Vegetation Clearance Standards and by returning to a pre-2003 regime where the extent of vegetation clearing is left to the individual discretion and pressures at each utility, there is no doubt that tree clearance conditions will deteriorate over time and put system reliability at greater risk of vegetation contact
Response: The SDT thanks you for your comments. At the request of FERC in Order 693, the SDT was asked to eliminate the fill-in-the-blank clearance requirements that are currently in FAC-003-1. A proven Engineering calculation was utilized to determine when a transmission line could spark over to vegetation without direct contact. Based on this calculation, each utility must determine what clearance levels need to be maintained as part of their TVMP. The current version does not preclude a utility from removing or pruning vegetation well beyond the MVCD, it just establishes a line in the sand that determines when a violation occurs. Individual TOs must establish a program that addresses the many variables that exist such as growth rates, vegetation management cycles, conductor sag and sway, etc. that could result in an encroachment of the MVCD which would be a direct violation of the standard. Establishing a specific clearance value to be attained during vegetation management activities is too prescriptive and is in direct conflict with the Results-Based Standard initiative that the SDT is currently implementing. Each TO must factor in delays and/or mitigation measures associated with stakeholder concerns but must clearly communicate the challenges with maintaining strict compliance with this zero-tolerance standard.				

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td>Greg Lange</td><td>Public Utility District No. 2 of Grant County</td><td>3</td><td>Negative</td><td>While this standard as written is a marked improvement to previous versions, to claim R1 and R2 as results based is simply not right. Had this standard revision not been advertised as the first RBS I probably would have voted yes. Results based by definition should be attained by something either happening or not and should be based on evidence that already exists. If you cause an outage and it is vegetation related then you violate. Why all the words around "managing vegetation encroachment" take care of that in the competency requirements.</td></tr>
<tr><td colspan="5">Response: The SDT thanks you for your comments. In a Results Based Standard, there are three different levels of defense to achieve the desired outcome (performance-based requirements, risk-based requirements and competency based requirements). R1 and R2 are considered Performance-Based requirements and are one component in the defense-in-depth strategy that is described in the Background Section of the current Draft. The MVCD is the minimum clearance distance before a spark-over occurs so R1 and R2 were designed to ensure that the TO manages vegetation appropriately before an outage occurs. If the TO was judged based on outages alone, the defense in depth strategy would fail and, thus, a less reliable standard would exist.</td></tr>
<tr><td>Gregory L Pieper</td><td>Xcel Energy, Inc.</td><td>1</td><td>Negative</td><td rowspan="4">Xcel Energy votes Negative for several reasons which are outlined in the comments submitted to NERC during the comment period that ran concurrently with this ballot. One of the primary objections is the requirement for an annual vegetation inspection. Xcel Energy urges the retention of the provision in the existing standard that allows the Transmission Owner to set the frequency of inspection.</td></tr>
<tr><td>Michael Ibold</td><td>Xcel Energy, Inc.</td><td>3</td><td>Negative</td></tr>
<tr><td>Liam Noailles</td><td>Xcel Energy, Inc.</td><td>5</td><td>Negative</td></tr>
<tr><td>David F. Lemmons</td><td>Xcel Energy, Inc.</td><td>6</td><td>Negative</td></tr>
<tr><td colspan="5">Response: The SDT thanks you for your comments. In FERC Order 693, the SDT was asked to look at setting a specific frequency for vegetation inspections across North America. This was a difficult task since vegetation characteristics vary across the continent but the team voted to accept an annual inspection frequency as a minimum and provide utilities the flexibility to include this mandatory vegetation inspection as part of a general line inspection.</td></tr>
<tr><td>Terry Harbour</td><td>MidAmerican Energy Co.</td><td>1</td><td>Affirmative</td><td rowspan="2">All rationale boxes should have a disclaimer at the top to the effect "For Guidance Only, Not for Enforcement".</td></tr>
<tr><td>Thomas C. Mielnik</td><td>MidAmerican Energy Co.</td><td>3</td><td>Affirmative</td></tr>
<tr><td colspan="5">Response: The SDT thanks you for your affirmative votes and comments. A “disclaimer” is addressed by the Standards Committee Process Subcommittee however its location remains under discussion.</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
Guy V. Zito	Northeast Power Coordinating Council, Inc.	10	Affirmative	Although NPCC and its members support the results based initiative and this proof of concept standard and format, there has been some concern with the proposed FAC-003-2. Some of NPCC's members that have active vegetation management programs have stated that in the application of Table 3 - specifically, the use of a "Minimum Distance from the Centerline of the Circuit". Mono-pole and frame construction have significantly different footprints which don't support a one size fits all approach. The use of Table 3 for 345kV, mono-pole construction could result in excessive clearing of additional forested edge on existing ROWs with little if any value added to system reliability and at great cost. There is an issue with use of the term "easements" in the definition and seek clarification on several questions-is there a reason the Active ROW only includes easements not fee ownership, license or some other right to occupy and manage the ROW? Would active ROW include "danger tree rights" on land? Not all entities that own transmission facilities and have vegetation management programs agree with these statements however there is cause enough for concern. In addition, this standard represents a "proof of concept for the "reliability based standards" initiative NERC is putting forward. NPCC RSC believe this initiative will result in better standards over time.
Response: The SDT thanks you for your affirmative vote and comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.				
Jason Shaver	American Transmission Company, LLC	1	Affirmative	ATC raises a concern on including Rationale Boxes plus Guidelines and Technical Basis as part of the NERC Reliability Standard. ATC recommends that the SDT either remove these sections or make them separate from the formal standard to eliminate any risk that these may be construed as requirements. An alternative method is to very clearly identify which parts of the standard are subject to compliance and considered mandatory and which are not considered requirements and are only for guidance in meeting the requirements.
Response: The SDT thanks you for your affirmative vote and comments. A "disclaimer" is addressed by the Standards Committee Process Subcommittee however its location remains under discussion.				
Horace Stephen Williamson	Southern Company Services, Inc.	1	Affirmative	Comments for this ballot are included in the Southern Company submitted comment form - Project 2007-07: Transmission Vegetation Management.
Richard J. Mandes	Alabama Power Company	3	Affirmative	
Anthony L Wilson	Georgia Power Company	3	Affirmative	

Voter	Entity	Segment	Vote	Comment
Gwen S Frazier	Gulf Power Company	3	Affirmative	
Don Horsley	Mississippi Power	3	Affirmative	
Response: The SDT thanks you for your affirmative votes and comments. Please refer to the SDT responses in the Comment Report.				
Ajay Garg	Hydro One Networks, Inc.	1	Affirmative	Hydro One would like to submit the following comments for consideration of the SDT. 1. In the application of Table 3 - specifically, the use of a "Minimum Distance from the Centerline of the Circuit", Mono-pole and frame construction have significantly different footprints which don't support a one size fits all approach. The use of Table 3 for 345kV, mono-pole construction could result in excessive clearing of additional forested edge on existing ROWs with little if any value added to system reliability and at great cost. 2. The use of the term "easements" in the definition needs clarification. For example, is there a reason the Active ROW only includes easements and not ownership, license or some other right to occupy and manage the ROW? Would active ROW include "danger tree rights" on land?
Michael D. Penstone	Hydro One Networks, Inc.	3	Affirmative	
Response: The SDT thanks you for your affirmative vote and comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.				
Richard J. Padilla	Pacific Gas and Electric Company	5	Affirmative	In principle we agree but we have the following concerns: Removes reference to ANSI A300 as an effective management strategy to comply with the standard. We often point to ANSI A300 to support our position of "wire zone - border zone" vegetation management practices in public education and legal disputes. However, Eastern and Southern utilities, who dominate the VMSDT, feel that ANSI A300 places constraints on their desire to perform bare ground clearing, which A300 and PG&E does not endorse. Most Western utilities support retaining reference to A300. Minimum clearance distances have been reduced from the current IEEE 516 distances to the distances derived from the Gallet equation. Reduced clearance distances make it more difficult to justify some work with property owners. FERC and NERC have also stated they are opposed to reduced clearances. The VMSDT spent much time and effort to construct the standard in a manner where there is violation gradation within some requirements. NERC and FERC have indicated they disagree with the latitude to ignore the VSL's as proposed
Response: The SDT thanks you for your affirmative vote and comments. The proposed draft of FAC-003-2 continues to make reference to ANSI A300 as a best practice but short of endorsement into a requirement. This represents the best compromise that the team could achieve. **Use of the Gallet Equation, contrary to your comment, provides for greater distances than IEEE-516-2003 under the same conditions of elevation, voltage and transient overvoltage factor. Please refer to the Technical Reference Document (posted on NERC webpage) for more information.** **The SDT indeed has worked hard to achieve a technically valid set of VSLs for this standard and believe its perspective is correct.**				

Voter	Entity	Segment	Vote	Comment
Steven Grego	MEAG Power	3	Affirmative	MEAG is voting yes in support of the improvements and significant effort that went into modifying FAC-003-2 with the understanding that the vegetation management standard will continue to develop and evolve. Vegetation management's increased visibility and dramatically increased oversight is resulting in increasingly defined and demanding language contained in the standard's requirements. Some of the new requirements overreach but the intent is clear, create and manage a vegetation management program to prevent outages that potentially create a cascading outage threat. As the application of this new standard is reviewed over time, improved requirements and measures based on experience and results should be used to further improve the standard. Additional lines of lesser voltages will now be included under this standard. The tendency may be to include a line when in doubt even if there is a remote possibility that it can potentially cause a threat of a cascading outage. The same philosophy will occur with rights-of-way. The legal right-of-way will be cleared even if it was secured for a future line of greater voltage. We need to continue to review FAC-003-2 for future improvements to achieve reasonableness in protecting against cascading outages without heaping unnecessary costs on electric consumers.
Steven M. Jackson	Municipal Electric Authority of Georgia	3	Affirmative	
Response: The SDT thanks you for your affirmative vote and comments. The SDT agrees with your comments.				
Michael T. Quinn	Oncor Electric Delivery	1	Affirmative	Oncor believes that the proposed standard is a significant improvement over the current standard. We strongly support the suggested VSL's as proposed by the VMSDT. However, we also take the position that adoption of a virtual binary VSL to describe an encroachment without an outage, as a high VSL doesn't adequately address the different levels of encroachment and any potential impact that could lead to Cascading. Oncor is not aware of any vegetation fall-ins or blow-ins that have caused or have lead to Cascading.
Response: The SDT thanks you for your affirmative vote and comments. The SDT has worked hard to achieve a technically valid set of VSLs for this standard and believe its perspective is correct.				
Chifong L. Thomas	Pacific Gas and Electric Company	1	Affirmative	PG&E believes this version is an improvement over the last draft. However, PG&E is concerned with the removal of the reference to ANSI A300 as an effective management strategy to comply with the standard. ANSI A300 provides clarity on the "wire zone - border zone" vegetation management practices. PG&E is also concerned that the minimum clearance distances have been reduced from the current IEEE 516 distances to the distances derived from the Gallet equation. Reduced clearance distances make it more difficult to implement certain types of work needed to support reliability.
Response: The SDT thanks you for your affirmative vote and comments. The proposed draft of FAC-003-2 continues to make reference to ANSI A300 as a best practice but short of endorsement into a requirement. This represents the best compromise that the team could achieve.				

Voter	Entity	Segment	Vote	Comment
Scott M. Helyer	Tenaska, Inc.	5	Affirmative	Please note that further changes may be needed to this standard to address issues related to generation interconnection facilities per other standards development efforts.
Response: The SDT thanks you for your affirmative vote and comments. The SDT is aware that a separate Project 2010-07 Transmission Requirements at the Generator Interface is underway to address the issue you raise.				
Brandy A Dunn	Western Area Power Administration	1	Affirmative	Please see comments provided on Official Comment Form
Response: The SDT thanks you for your affirmative vote and comments. Please refer to the responses in the Comment Report.				
Donald S. Watkins	Bonneville Power Administration	1	Affirmative	Regarding footnote number 2, and the description of an "Active Transmission Line Right of Way", BPA has the following comments: The distance is reasonable in the table, but due to widely varying designs of structures it does not give a relationship of the outside wire to edge of ROW. It should be noted as outside wire, phase or conductor to edge of ROW. In addition, the effective date should allow transmission owners time to achieve this distance, perhaps one cycle. Other Comments: The basis of managing vegetation to MVCD in Table 2 (essentially withstand distances) will likely prove problematic. BPA believes NERC should develop an additional table that calls out minimum "buffers" based on attributes such as line voltage, line rating etc. This table should be a companion to Table 2. It is NERC's responsibility to regulate and we believe that they should do so. In this case, the loss of flexibility for the owners is not necessarily a bad thing.
Rebecca Berdahl	Bonneville Power Administration	3	Affirmative	
Francis J. Halpin	Bonneville Power Administration	5	Affirmative	
Brenda S. Anderson	Bonneville Power Administration	6	Affirmative	
Response: The SDT thanks you for your affirmative votes and comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.				
Tim Kelley	Sacramento Municipal Utility District	1	Affirmative	SMUD appreciates the efforts of the Drafting Team. However, use of the phrase “intentional time delay” in R4 no clear definitive time frame for “intentional time delay” this leads to difficulty in its definition. SMUD respectively offers the recommendation for the DT to use a term along the lines of “expeditious.”
James Leigh-Kendall	Sacramento Municipal Utility District	3	Affirmative	
Mike Ramirez	Sacramento Municipal Utility District	4	Affirmative	
Bethany Wright	Sacramento Municipal Utility District	5	Affirmative	
Response: The SDT thanks you for your affirmative votes and comments. The SDT struggled with the selection of language in R4 and considered your term among many others. The team ended up with the drafted version as the best compromise.				

Voter	Entity	Segment	Vote	Comment
Marjorie S. Parsons	Tennessee Valley Authority	6	Affirmative	Suggest a clarifying change to the language in footnote 2 and or Table 3 to address those lines that have ROW width variations from the prevailing width due to factors unrelated to the needs for vegetation maintenance for the subject line. Add the following sentence to footnote 2 "The widths and distances in Table 3 shall be that prevailing width of the ROW exclusive of any variations in the prevailing width due to factors unrelated to the needs for vegetation maintenance for the subject line." TVA asserts that the new language in R1, R2, M1, and M2 in concert with new language in R3 and M3 are fully adequate and superior to any of the proposed alternative A-F. TVA asserts that the VSLs as proposed by the SDT are appropriate since they reflect in various degrees the typical types of right of way maintenance failure. For example vegetation removal from under the conductors should be the highest priority work, followed by vegetation removal in the side-growth/blow-out areas, and lastly of all fall-in risks should be removed. TVA suggests that another sentence be added to the end of Section 4.4 Other, as follows: Nothing is this Standard is shall be used to require the Transmission Owner to acquire additional easement rights beyond those currently owned, or to perform any maintenance outside the limits of its legal rights.
Response: The SDT thanks you for your affirmative vote and comments. Please see drafting team responses to your same comments in the Comment Report.				
Paul B. Johnson	American Electric Power	1	Affirmative	The VSL chart states that it is a Lower Violation if the TO has an encroachment into the MVCD observed in real time, absent a sustained outage. While the Moderate and High categories specifically note that the reference is to inside the right-of-way, the Lower level does not. Should the Lower category read: " The Transmission Owner has an encroachment into the MVCD from inside the right-of-way in real time, absent a Sustained Outage"?
Edward P. Cox	AEP Marketing	6	Affirmative	
Response: The SDT thanks you for your affirmative votes and comments. The suggested edit has been considered and the SDT determined that no change to the VSL would be made.				
Robert Smith	Duke Energy	5	Affirmative	This Version 2 of FAC-003 takes a big step forward to clarify expectations and compliance with the standard. The results-based format is a big improvement.
Response: The SDT thanks you for your affirmative vote and comment.				

Voter	Entity	Segment	Vote	Comment
George T. Ballew	Tennessee Valley Authority	5	Affirmative	TVA suggests a clarifying change to the language in footnote 2 and or Table 3 to address those lines that have ROW width variations from the prevailing width due to factors unrelated to the needs for vegetation maintenance for the subject line. Add the following sentence to footnote 2 “The widths and distances in Table 3 shall be used as the prevailing width of the ROW regardless of any variations in width due to factors unrelated to the needs for vegetation maintenance for the subject line.” TVA asserts that the VSLs as proposed by the SDT are appropriate since they reflect in various degrees the typical types of right of way maintenance failure. For example vegetation removal from under the conductors should be the highest priority work, followed by vegetation removal in the side-growth/blow-out areas, and lastly of all fall-in risks should be removed. TVA suggests that another sentence be added to the end of Section 4.4 Other, as follows: Nothing in this Standard shall be used to require the Transmission Owner to acquire additional easement rights beyond those currently owned, or to perform any maintenance outside the limits of its legal rights.
Response: The SDT thanks you for your affirmative votes and comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed. **The SDT agrees with your comment on the VSLs, and the SDT points out that the following sentence at the end of Section 4.4 is comparable to your suggestion, “Nothing in this section should be construed to limit the Transmission Owner’s right to exercise its full legal rights on the ROW.”**				
Spencer Tacke	Modesto Irrigation District	4	Affirmative	We approve of the proposed revised standard as written. However, we have a concern about the Minimum Vegetation Clearance Distance (MVCD) of 2.97 feet shown in Table 2 for 230kV lines, as being too small. We will continue to maintain a much larger clearance than specified in Table 2, and in this case, no less than 10 feet of clearance for 230kV lines, taking into consideration the maximum sag designed for a given line. Thank you.
Response: The SDT thanks you for your affirmative vote and comments. The MVCD was set up to be a “minimum” distance to never violate. Certainly, each TO must maintain larger clearances in order to account for growth, movement of conductor and other factors that influence the distance between the conductor and vegetation. Use of the Gallet Equation provides for greater distances than IEEE-516-2003 under the same conditions of elevation, voltage and transient overvoltage factor. Please refer to the Technical Reference Document (posted on NERC webpage) for more information.				
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Abstain	Entities have a problem with other Government Agencies in tha they are not real receptive for Vegetation Management. Burea of Land Management will usually take 2 years to get permission to trim vegetation in BLM ROW. State Land Department will usually not let you cut any cactuses in ROW on State land. ROW crossing on a Sovereign Indian Reservation is just as bad. If this is such a big issue for FERC/NERC, then they need to get other governmental agencies on board with them.

Voter	Entity	Segment	Vote	Comment
Response: **The SDT thanks you for your comments. Jurisdictional issues need to be addressed in other appropriate arenas. The Utility Arborist Association among other groups have sought to coordinate cooperation between agencies in the past.**				

Consideration of Comments on Draft 5 of FAC-003-2

Project 2007-07 Vegetation Management — September 30, 2011

Background

The Transmission Vegetation Management Drafting Team thanks all commenters who submitted comments on the 5th Draft of FAC-003-2 Transmission Vegetation Management standards. These standards were posted for a 30-day public comment period from January 27, 2011 through February 28, 2011. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 41 sets of comments, including comments from more than 106 different people from approximately 63 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

Summary of Changes

In order to be consistent with the latest version of NERC's Results Based Standards template, the heading "Objective" was replaced with "Purpose," and the numbering, headings, and sections were reformatted as necessary.

One repeated concern was whether or not "danger trees" rights outside the Right-of-Way (ROW) should be an extension of the ROW. The SDT has limited the definition of Right-of-Way to a corridor of land with a defined width to operate a transmission line, which does not include danger tree rights.

Another repeated concern was reference to the term "blowout standard" and commenters were asking for more clarification and/or a specific definition of that term. To this line of comments the SDT responded, "the definition includes a series of options that give the Transmission Owner latitude in establishing ROW width. It does not require selecting a single method for its system. The term blowout standard is not capitalized and is not a defined term, and is intended to represent whatever conductor "blow out" (as opposed to vegetation "blow in") design criteria were used when the line was constructed. This phrase in the definition allows a Transmission Owner to use its internal engineering standards or the general engineering standards that were in effect when the line was constructed to determine the ROW width."

A request was made to include the definition of MVCD within the definition section of the standard. The SDT agreed with the commenter's request and used the appropriate portion of the existing language in the rationale text box associated with R1 for the MVCD definition. The SDT understands that this term will be added to the NERC glossary coincident with this standard becoming effective. This is not a substantive change to the standard, it is merely procedural.

The SDT made minor changes to the footnotes in response to several requests.

There was some concern expressed regarding the relationships between the VSLs and language in the requirements. The SDT revised the language in the Rationale box to explain the program performance relationships between types of encroachments, faults and outages, and various types of failed maintenance, and how the various types of failed maintenance have historically been associated with known vegetation related events.

One commenter requested that "of applicable lines" be added to the requirements and VSL verbiage to clearly denote applicability within the requirements and VSL verbiage. The SDT made those changes as requested to the requirements, measures and VSLs.

Two commenters requested an example be added to the Guidelines and Technical Basis similar to the examples in R6 to clarify that the % calculations should be based on the Annual Plan as modified; the SDT added the example as requested.

http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 404-446-2563 or via email at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.1

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Joe Spencer	SERC Vegetation Management sub-committee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Fatima Ahmed	SEPA	SERC	
2.	Gerry Beckerie	Ameren	SERC	
3.	Todd Bennett	AECI	SERC	
4.	Brent Davis	Entergy	SERC	
5.	Richard Dearman	TVA	SERC	
6.	Jack Gardner	Progress Energy	SERC	
7.	Jeff Hackman (chair)	Ameren	SERC	
8.	Ralph Hale	Entergy	SERC	
9.	Jerry Lindler	SCANA	SERC	
10.	Larry Rodriguez	Entegra Power	SERC	
11.	Joe Spencer	SERC Reliability	SERC	
12.	John Troha	SERC Reliability	SERC	
13.	Marc Tunstall	Fayetteville Public Works Com	SERC	
14.	Terry Wilson	Power South	SERC	

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Sasa Maljukan	Hydro One Networks	X									

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Kiguel	Hydro One Networks Inc	NPCC	1
2.	Jonathan Marriott	Hydro One Networks Inc.		1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Bohdan M. Dackow	US Power Generating Company (USPG)	NPCC	NA
6.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
7.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
8.	Brian Evans-Mongeon	Utility Services	NPCC	8
9.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
10.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	David Kiguel	Hydro One Networks Inc.	NPCC	1
13.	Michael R. Lombardi	Northeast Utilities	NPCC	1
14.	Randy MacDonald	New Brunswick Power Transmission	NPCC	1
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Chantel Haswell	FPL Group, Inc.	NPCC	5
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Saurabh Saksena	National Grid	NPCC	1
20.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Deborah Schaneman	Platte River Power Authority Substation Maintenance Group	X		X		X	X				

Additional Member	Additional Organization	Region	Segment

			Selection	
1.	Scott Rowley	Platte River Power Authority	WECC	1, 3, 5, 6
2.	Gary Whittenberg	Platte River Power Authority	WECC	1, 3, 5, 6
3.	Aaron Johnson	Platte River Power Authority	WECC	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
5.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charles Sheppard	BPA, Transmission Field Services	WECC	1
2.	Steven Narolski	BPA, Transmission Field Services	WECC	1
3.	Frank Weintraub	BPA, Transmission Lign Design	WECC	1
4.	Jennifer Bailey	BPA, Transmission, Construction Mgmt and Inspect	WECC	1
5.	Don Swanson	BPA, Transmission TLM Technical Services	WECC	1
6.	Steve Bottemiller	BPA, Transmission, Real Property Support Svcs	WECC	1
7.	Vince Ierulli	BPA, Transmission Lign Design	WECC	1
8.	Mike Staats	BPA, Transmission Engineering	WECC	1
9.	Jenifur Rancourt	BPA, FERC Compliance	WECC	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Doug Keegan	NERC Staff										
7.	Group	David Thorne	Pepco Holdings Inc and Affiliates	X		X							

Additional Member	Additional Organization	Region	Segment Selection	
1.	Dana Small		RFC	1
2.	Lisa E Pfeifer		RFC	1
3.	Pat J Byrne		RFC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rebecca Spach	FE	RFC	1
2.	Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6
3.	Dave Folk	FE	RFC	1, 3, 4, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

4.	Mike Ferncez	FE	RFC	1
5.	Shawn Standish	FE	RFC	1
6.	Katrina Schnobrich	FE	RFC	

				1	2	3	4	5	6	7	8	9	10
9.	Group	Mike Garton	Dominion Electric Market Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Michael Gildea	Dominion Resources Services, Inc.	NPCC	5
2.	Louis Slade	Dominion Resources Services, Inc.	SERC	5
3.	Connie Lowe	Dominion Resources Services, Inc.	RFC	6
4.	Michael Crowley	Dominion Virginia Power	SERC	1, 3

				1	2	3	4	5	6	7	8	9	10
10.	Individual	JT Wood	Southern Company Transmission	X		X							
11.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
12.	Individual	Cynthia Oder	Salt River Project	X		X		X	X				
13.	Individual	Luke Diruzza	Tampa Electric Company	X		X		X	X				
14.	Individual	Silvia Parada Mitchell	NextEra Energy	X		X		X	X				
15.	Individual	Jennifer Wright	SDG&E	X		X		X					
16.	Individual	JAMES SMITH	ASSET MANAGEMENET	X									
17.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie (NCR07112)	X									
18.	Individual	Michael Gammon	Kansas City Power & Light	X		X		X	X				
19.	Individual	Joe Petaski	Manitoba Hydro	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
20.	Individual	Weston Davis	Central Maine Power Company - IberdrolaUSA	X									
21.	Individual	Gordon Rawlings	BC Hydro	X	X	X		X					
22.	Individual	Andrew Pusztai	American Transmission Company, LLC	X									
23.	Individual	Thad Ness	American Electric Power	X		X		X	X				
24.	Individual	William Rees	Baltimore Gas and Electric Co.	X									
25.	Individual	Jason Regg	TVA	X									
26.	Individual	Michael Schiavone	Niagara Mohawk Power Corporation (dba National Grid)			X							
27.	Individual	Michael Pakeltis	CenterPoint Energy	X									
28.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
29.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
30.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									
31.	Individual	Kirit Shah	Ameren	X		X		X	X				
32.	Individual	Amy Kupferberg	Individual	NA									
33.	Individual	George Czerniewski	Consolidated Edison Company of New York, Inc. - Transmission Line Maintenance	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
34.	Individual	andres lopez	USACE					X				X	
35.	Individual	CJ Ingersoll	CECD			X							
36.	Individual	Edward J Davis	Entergy Services, Inc	X		X		X	X				
37.	Individual	David Burke	Orange and Rockland Utilities, Inc.	X		X							
38.	Individual	Saurabh Saksena	National Grid	X		X							
39.	Individual	Steve Rueckert	Western Electricity Coordinating Council										X
40.	Individual	Jody Nelson	Georgia Transmission Corp.	X									
41.	Individual	T. Wiley	Northern Indiana Public Service Company	X		X							

1. **The SDT proposes a revised NERC Glossary definition for Right-of-Way (ROW). This revised definition will be used in lieu of the Active Transmission Line ROW. Do you agree? If answer is no, please explain.**

Summary Consideration: There are 40 comments; 29 of those comments were in agreement with the definition, and 11 were in disagreement.

One repeated concern in the disagreements was whether or not "danger trees" rights outside the Right-of-Way (ROW) should be an extension of the ROW. The SDT responded "The SDT has limited the definition of Right-of-Way to a corridor of land with a defined width to operate a transmission line. This does not include danger tree rights."

Another repeated concern in the disagreements was reference to the term "blowout standard" and commenters were asking for more clarification and/or a definition of that term. To this line of comment the SDT responded "The definition includes a series of options that gives the Transmission Owner latitude in establishing ROW width. It does not require selecting a single method for its system. The term blowout standard is not capitalized and is not a defined term, and is intended to represent whatever conductor "blow out" (as opposed to vegetation "blow in") design criteria were used when the line was constructed. This phrase in the definition allows a Transmission Owner to use its internal engineering standards or the general engineering standards that were in effect when the line was constructed to determine the ROW width."

A request was made to include the definition of MVCD within the definition section of the standard. The SDT agreed with the commenter's request and used the appropriate portion of the existing language in the rationale text box associated with R1 for the MVCD definition. The SDT understands that this term will be added to the NERC glossary coincident with this standard becoming effective. This is not a substantive change to the standard, it is merely procedural.

A request was made to remove the existing and future definition of ROW from the glossary. The SDT understands that this is not consistent with the NERC intent for each repeated acronym used in multiple requirements to be available in the glossary for ready reference.

A request was made to change the definition of ROW to include special permissions given by some property owners. To this the SDT responded "The SDT has limited the definition of Right-of-Way to a corridor of land with a defined width to operate a transmission line. The SDT does not propose to change the definition because of the numerous and varied special property owner permissions that may exist, and which are not always legally binding."

A concern within one disagreement was related to possible misuse of the "pre-2007 vegetation maintenance records." The SDT explained that this term was placed in the definition as a method to cover situations where the other alternatives are not viable. The SDT will address this issue in the Technical Reference Document.

Organization	Yes or No	Question 1 Comment
SERC Vegetation Management sub-committee	No	We agree with the proposed definition as a replacement for active transmission ROW, however, in a review of NERC standards, the term ROW is not used except in FAC-003. It is therefore recommended that the term be removed from the NERC glossary. r
Response: The SDT thanks you for your comments. The SDT considered your request but cannot implement it because it is not consistent with the NERC Standards Development Process for defining the use of a term solely within a standard itself. All defined terms must be included in the glossary.		
Hydro One Networks	No	The revised definition of ROW is unclear in regards to the application of standards and/or historic records as a means of determining ROW width; is it necessary for a TO to select one method to apply in all cases, or can each span be treated in the manner deemed most appropriate by the TO? Additionally "blowout Standard" has not been defined in the document or in the technical paper, and therefore it is not clear exactly how this method would be applied, and subsequently defended under scrutiny.
Response: The SDT thanks you for your comments. The definition includes a series of options that give the Transmission Owner latitude in establishing ROW width. It does not require selecting a single method for its system. The term blowout standard is not capitalized and is not a defined term, and is intended to represent whatever conductor "blow out" (as opposed to vegetation "blow in") design criteria were used when the line was constructed. This phrase in the definition allows a Transmission Owner to use its internal engineering standards or the general engineering standards that were in effect when the line was constructed to determine the ROW width.		
Northeast Power Coordinating Council	No	There was no definition of ROW listed in FAC-003-1. The revised definition of ROW in FAC-003-2 is unclear regarding the application of standards and/or historic records as a means of determining

Organization	Yes or No	Question 1 Comment
		ROW width. Is it necessary for a TO to select one method to apply in all cases, or can each span be treated in the manner deemed most appropriate by the TO? "Blowout standard" has not been defined in the document, technical paper, or NERC Glossary and it is not clear what this method is, and exactly how it would be applied. It could not be defended under scrutiny. It is still unclear whether Danger Tree rights are included in this definition.In the NERC Glossary of Terms, Right-of-Way (ROW) is defined as "A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines." Propose keeping this definition.Is encroachment into the MVCD, or (MVCD plus additional distance as defined by the TO)? MVCD, as specified within the body of FAC-003-2 "is a calculated minimum distance stated in feet (meters) to prevent flashover between conductors and vegetation, for various altitudes and operating voltages." MVCD should be "formally" defined in this document, and the NERC Glossary. Can a list/database be established in 2011 that lists the widths for the pre-2007 vegetation management records?
Response: The SDT thanks you for your comments. The existing ROW definition in the glossary was created by and for the FAC-003-1 and was moved there when that standard was adopted. The definition includes a series of options that give the Transmission Owner latitude in establishing ROW width. It does not require selecting a single method for its system. The term blowout standard is not capitalized and is not a defined term, and is intended to represent whatever conductor "blow out" (as opposed to vegetation "blow in") design criteria were used when the line was constructed. This phrase in the definition allows a Transmission Owner to use its internal engineering standards or the general engineering standards that were in effect when the line was constructed to determine the ROW width. The SDT has limited the definition of Right-of-Way to a corridor of land with a defined width to operate a transmission line. This does not include danger tree rights. The definition of the MVCD is now added to this Standard. While use of the pre-2007 records is a compliance issue and is not in the purview of the SDT, it is the intent of the language in the definition that you could use this information.		
Platte River Power Authority Substation Maintenance Group	No	We agree that the ROW width in no case exceeds the TO's legal rights but may be less. We do not agree that the revised NERC Glossary definition for Right-of-Way addresses paragraph 734 of FERC Order 693 "that rights-of-way be defined to encompass the required clearance areas instead of the

Organization	Yes or No	Question 1 Comment
		corresponding legal rights, and that the standards should not require clearing the entire right-of-way when the required clearance for an existing line does not take up the entire right-of-way". The engineering or construction standards for establishing the width of the corridor outlined in the definition are in most cases not useful. We will continue to rely on our easements and legal rights with this definition. We believe the Active Transmission Line ROW definition in the previous version more clearly addressed paragraph 734 of FERC Order 693.
Response: The SDT thanks you for your comments. The standard covers lines that have been built over many years where records could be lost. The ROW definition provides three alternatives to determine the width of the corridor to be maintained.		
NERC Staff	No	NERC supports a revised definition and prefers the definition in Draft 5 over the Active Transmission Line ROW definition used in Draft 4. NERC believes the use of the term "pre-2007 vegetation maintenance records" in the proposed definition is ambiguous and will likely be interpreted differently throughout the industry. Therefore, NERC supports this change subject to removing the aforementioned term.
Response: The SDT thanks you for your comments. The phrase "…pre-2007 vegetation maintenance records…" was placed in the definition as a method to cover situations where the other alternatives are not viable. The SDT has addressed this issue in detail in the Technical Reference Document.		
FirstEnergy	No	Although for the most part we agree with the changes to the definition of ROW, we suggest the following changes. 1. The last sentence of the definition states "The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria." We do not agree with the phrase "in no case exceeds the Transmission Owner's legal rights" because there could be instances where special permission has been granted by landowners to the TO. We suggest revising this statement to "The ROW width may be less than the Transmission Owner's granted rights based on the aforementioned criteria."

Organization	Yes or No	Question 1 Comment
		2. Regarding the phrase "blowout standard" used in the definition, we are assuming this is in reference to the company specific calculations for sag and sway on not on any one specific industry standard. We suggest clarification such as "Transmission Owner's specific blowout or sag and sway analysis in effect when the line was built".
Response: The SDT thanks you for your comments. The SDT has limited the definition of Right-of-Way to a corridor of land with a defined width to operate a transmission line. The SDT does not propose to change the definition because of the numerous and varied special property owner permissions that may exist, and which are not always legally binding. The term blowout standard is not capitalized and is not a defined term, and is intended to represent whatever conductor “blow out” (as opposed to vegetation “blow in”) design criteria were used when the line was constructed. This phrase in the definition allows a Transmission Owner to use its internal engineering standards or the general engineering standards that were in effect when the line was constructed to determine the ROW width.		
Central Maine Power Company - IberdrolaUSA	No	The definition does not define transmission owner responsibility for areas covered by “danger tree” rights. This area is outside the maintained width but for economic and social reasons the transmission owner can not remove all danger trees. Utilities have procedures in place to remove the hazard trees but it is not practical to remove all danger trees that have the potential to violate the MVCD should they fail. This area of the definition requires clarification.
Response: The SDT thanks you for your comments. The SDT has limited the definition of Right-of-Way to a corridor of land with a defined width to operate a transmission line. This does not include danger tree rights.		
TVA	No	I suggest that "arboricultural activities or horticultural or agricultural activities be removed and changed to installation, removal or digging of vegetation.
Response: The SDT thanks you for your comments. The changes have been made in the footnotes.		
Niagara Mohawk Power Corporation (dba National	No	It is still unclear whether Danger Tree rights are included in this definition. Additional question: Can we establish a list/database in 2011 stating the widths for the pre-2007 vegetation

Organization	Yes or No	Question 1 Comment
Grid)		management records? There is no definition of ROW listed in FAC-003-1, however in the NERC Glossary of Terms, Right-of-Way (ROW) is defined as "A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines." We propose keeping this definition.
Response: The SDT thanks you for your comments. The SDT has limited the definition of Right-of-Way to a corridor of land with a defined width to operate a transmission line. This does not include danger tree rights. While use of the pre-2007 records is a compliance issue and is not in the purview of the SDT, it is the intent of the language in the definition that you could use this information.		
CenterPoint Energy	No	CenterPoint Energy agrees with the removal of "Active Transmission Line ROW" as a defined term. The change in the NERC Glossary definition for Right-of-Way (ROW) alone, however, does not address all of the remaining interpretation issues within the Standard that still exist. The following issues still require resolution: 1. The "force majeure" was moved from the Applicability section to a footnote, and is no longer an encompassing exception for each Requirement. Therefore, the "force majeure" footnote needs to be applied not only to R1, R2, R6, and R7 but also R4 and R5. For R4, notification to the control center would likely be restricted during a natural disaster. For R5, correction action by the control center may not be possible during a natural disaster. 2. The exception for applicability beyond the "Rating and all Rated Electrical Operating Conditions" should be included not only in R1, R2, and R3, but also R5 and R7. For R5 and R7, the encroachment into the MVCD should consider whether the line is operating within its design limits. 3. The use of the term "Fault" in M1 and M2 should be revised to "Sustained Outage". A "Fault" can be associated with a Momentary Outage or a Sustained Outage. The scope of R1 and R2 is specific to Sustained Outages only. The Periodic Data Submittal is specific to Sustained Outages only as well. If a later confirmation of a "Fault" by the Transmission Owner indicates that a vegetation encroachment into the MVCD was due to a fall-in from inside the ROW, yet caused only

Organization	Yes or No	Question 1 Comment
		a Momentary Outage, the Transmission Owner would be in violation of R1 because M1 considers it to be the equivalent of a Real-time observation. The current scope of the Standard is not intended to include Momentary Outages. If it was, the Periodic Data Submittal would capture this type of outage, which it does not. 4. In the Introduction Section 5 - Background, fall-ins are characterized as “statistically intermittent” and “these types of events are highly unlikely to cause large-scale grid failures”. CenterPoint Energy agrees and therefore recommends that fall-ins be excluded from the Requirements R1, R2, and Periodic Data Submittal of outages. This would negate the need for determining the limits of the ROW, thus simplifying the Standard to a great margin while not sacrificing the emphasis of the Standard. The Draft 5 Background Information states the criteria for developing a results-based reliability standard such that “each requirement should identify a clear and measurable expected outcome.” When the determination of the limits of the ROW goes beyond the interpretation of the legal limits of the ROW, it adds a level of complexity that may be unclear and not deterministically measurable. 5. For R6, CenterPoint Energy believes the detailed rationale and studies used for the determination of the required one year inspection cycle should be included in the Guidelines and Technical Basis. The explanation provided in the Rationale that it is “based upon average growth rates across North America and on common utility practice” are unfounded and arbitrary without a specific reference to a North American study. 6. R7 contains the phrase, “provided they do not put the transmission system at risk of a vegetation encroachment”. CenterPoint Energy recommends this phrase be replaced with the more specific terminology used in the Rationale for R7 and R3: “provided they do not allow encroachment of vegetation into the MVCD.” 7. CenterPoint Energy believes the Periodic Data Submittal should be clarified as to the specific conditions under which Sustained Outages are reported. There is a reference to footnote 2 regarding the exclusion for the “force majeure”; however, the exclusion for lines operating outside their design limits as mentioned in R1, R2, and R3 is missing. CenterPoint Energy believes the

Organization	Yes or No	Question 1 Comment
		wording should be changed to include all applicable exclusions for added clarity and recommends the following wording: "The Transmission Owner will submit a quarterly report to its Regional Entity, or Regional Entity's designee, identifying all Sustained Outages of applicable transmission lines operating within their Facility Rating and all Rated Electrical Operating Conditions as determined by the Transmission Owner to have been caused by vegetation, except as excluded in footnote 2, which includes as a minimum, the following:" 8. The Guidelines and Technical Basis and the Technical Reference with the Gallet Equation should be combined into one document as a supplement to the Standard to avoid duplication in wording and misinterpretation of context. 9. The Guideline and Technical Basis under Requirement R6 refers to the "percentage of the required ROW inspections completed" and should be revised to match the wording of R6 and the VSL for R6 as the "percentage of applicable transmission line inspections completed." 10. CenterPoint Energy agrees that the Rationale test boxes should be deleted from the Standard and applicable explanatory text be included within the Guidelines and Technical Basis. 11. The Guidelines and Technical Basis should contain specific examples for determining if a fall-in is considered inside or outside the ROW. 12. CenterPoint Energy recommends modifying the Technical Reference section regarding "Selecting a Maintenance Approach" to delete the sentences beginning with, "If constraints cannot be overcome and if design clearances are sufficient..." and continuing through to, "identified early for rectification." This example may lead the public to inappropriately ask the utilities for exceptions to allow vegetation beneath the transmission lines, and it also does not address the dynamics of future modifications to the transmission lines (e.g. higher operating temperatures or new conductors) that may necessitate reduced clearances to ground, thus requiring removal of now mature vegetation. The example should not be included in a Standard intended to reduce vegetation risks to the transmission system. It is also in conflict with later statements in the Technical Reference regarding Set Objectives which emphasize maintaining access and clear lines of

Organization	Yes or No	Question 1 Comment
		sight. 13. In general, CenterPoint Energy strongly believes the proposed FAC-003-2 has gone far beyond what was contemplated by the Commission in FERC Order 693. The Commission's determination dealt with the following areas: (1) applicability; (2) inspection cycles; and (3) minimum clearances on National Forest Service lands. For instance, in Paragraph 729, the Commission states, "As proposed in the NOPR, the Commission approves Reliability Standard FAC-003-1 with no proposed modification on the issue of clearances. The Commission reaffirms its interpretation that FAC-003-1 requires sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions...." Rewriting the minimum clearances introduces a new set of confusing definitions, and further burdens the Transmission Owners with new documentation requirements while providing little, if any, benefit when compared to the Clearance 2 concept in the existing Standard.A preferred approach would be to incorporate the following few items into the existing Standard FAC-003-1: (1) the RC versus the RRO; (2) the designation of a specific inspection frequency; (3) the Gallet equation; and (4) the applicability to National Forest Service lands.
Response: The SDT thanks you for your comments: For clarity the SDT separated various items in your comments and repeated them below with the numbered responses: CenterPoint Energy agrees with the removal of "Active Transmission Line ROW" as a defined term. The change in the NERC Glossary definition for Right-of-Way (ROW) alone, however, does not address all of the remaining interpretation issues within the Standard that still exist. The following issues still require resolution: 1. The "force majeure" was moved from the Applicability section to a footnote, and is no longer an encompassing exception for each Requirement. Therefore, the "force majeure" footnote needs to be applied not only to R1, R2, R6, and R7 but also R4 and R5. For R4, notification to the control center would likely be restricted during a natural disaster. For R5, correction action by the control center may not be possible during a natural disaster. **Response:** Thank you for your comment. The SDT considers the term "without intentional delay" to be adequate coverage for force majeure issues in R4. R5 requires that if you cannot perform work regardless of the reason you must come up with a plan to ensure that you prevent		

Organization	Yes or No	Question 1 Comment

encroachments, therefore a force majeure exemption is not applicable.

2. The exception for applicability beyond the “Rating and all Rated Electrical Operating Conditions” should be included not only in R1, R2, and R3, but also R5 and R7. For R5 and R7, the encroachment into the MVCD should consider whether the line is operating within its design limits.

Response: The SDT thanks you for your comments. The SDT made the suggested changes to remove references to arboricultural, horticultural or agricultural activities from the footnote 2, but did not adopt the suggestion for the new footnote 6 which replaces the footnote 4 to which you refer” because that footnote 4 is concerned with completing the annual work plan, The SDT does not envision that actions by property owners such as installation, or removal or digging of vegetation as a valid impediment to completion of the annual work plan. However this term is relevant in R1 and R2 and as such is within foot note 2 because such actions do occur from time to time without the transmission Owner’s knowledge and do then result in conditions that could lead to encroachments and outages before the Transmission Owner has the opportunity to rectify the condition.

3. The use of the term “Fault” in M1 and M2 should be revised to “Sustained Outage”. A “Fault” can be associated with a Momentary Outage or a Sustained Outage. The scope of R1 and R2 is specific to Sustained Outages only. The Periodic Data Submittal is specific to Sustained Outages only as well. If a later confirmation of a “Fault” by the Transmission Owner indicates that a vegetation encroachment into the MVCD was due to a fall-in from inside the ROW, yet caused only a Momentary Outage, the Transmission Owner would be in violation of R1 because M1 considers it to be the equivalent of a Real-time observation. The current scope of the Standard is not intended to include Momentary Outages. If it was, the Periodic Data Submittal would capture this type of outage, which it does not.

Response: Thank you for your comment. The reporting of Sustained Outages is simply to fulfill routine data submission. The SDT does not intend to create a system that requires a root cause analysis of all Faults which are not Sustained Outages. The SDT did intend for those Faults as referenced in M1 and M2 to be considered the equivalent of an encroachment observed in real time. The SDT also notes that the term Fault is an existing defined term and momentary interruption is not.

4. In the Introduction Section 5 - Background, fall-ins are characterized as “statistically intermittent” and “these types of events are highly unlikely to cause large-scale grid failures”. CenterPoint Energy agrees and therefore recommends that fall-ins be excluded from the Requirements R1, R2, and Periodic Data Submittal of outages. This would negate the need for determining the limits of the ROW, thus simplifying the Standard to a great margin while not sacrificing the emphasis of the Standard. The Draft 5 Background Information states the criteria for developing a results-based reliability standard such that “each requirement should identify a clear and measurable expected outcome.” When the determination of the limits

Organization	Yes or No	Question 1 Comment

of the ROW goes beyond the interpretation of the legal limits of the ROW, it adds a level of complexity that may be unclear and not deterministically measurable.

Response: Thank you for your comment. Fall-ins from inside the ROW are indicators of a poor performing vegetation management program. The definition of Right-of-Way identifies methods to define the width of the corridor establishing whether vegetation was located within the ROW and subject to the Transmission Owner's legal rights.

5. For R6, CenterPoint Energy believes the detailed rationale and studies used for the determination of the required one year inspection cycle should be included in the Guidelines and Technical Basis. The explanation provided in the Rationale that it is "based upon average growth rates across North America and on common utility practice" are unfounded and arbitrary without a specific reference to a North American study.

Response: Thank you for your comment. The SDT established an inspection cycle at least once per calendar year and with no more than 18 months between inspections on the same ROW. This cycle was based on industry comments submitted to Draft 1 of this standard ending on 11-25-2008

6. R7 contains the phrase, "provided they do not put the transmission system at risk of a vegetation encroachment". CenterPoint Energy recommends this phrase be replaced with the more specific terminology used in the Rationale for R7 and R3: "provided they do not allow encroachment of vegetation into the MVCD."

Response: Thank you for your comment. The SDT agrees and has made the requested change to the draft standard.

7. CenterPoint Energy believes the Periodic Data Submittal should be clarified as to the specific conditions under which Sustained Outages are reported. There is a reference to footnote 2 regarding the exclusion for the "force majeure"; however, the exclusion for lines operating outside their design limits as mentioned in R1, R2, and R3 is missing. CenterPoint Energy believes the wording should be changed to include all applicable exclusions for added clarity and recommends the following wording: "The Transmission Owner will submit a quarterly report to its Regional Entity, or Regional Entity's designee, identifying all Sustained Outages of applicable transmission lines operating within their Facility Rating and all Rated Electrical Operating Conditions as determined by the Transmission Owner to have been caused by vegetation, except as excluded in footnote 2, which includes as a minimum, the following:"

Response: Thank you for your comment. The SDT added your recommended language on "within its Rating and all Rated Electrical Operating

Organization	Yes or No	Question 1 Comment

Conditions".

8. The Guidelines and Technical Basis and the Technical Reference with the Gallet Equation should be combined into one document as a supplement to the Standard to avoid duplication in wording and misinterpretation of context.

Response: Thank you for your comment. The Guideline and Technical section is part of the NERC Results Based Standard format. The Technical Reference is a supplemental document that explains the VMSDT thought process in developing the requirements and applies to this version of the standard.

9. The Guideline and Technical Basis under Requirement R6 refers to the "percentage of the required ROW inspections completed" and should be revised to match the wording of R6 and the VSL for R6 as the "percentage of applicable transmission line inspections completed."

Response: Thank you for your comment. VSL's for R6 has been changed to align with the NERC Standard Development guidelines to "a Transmission Owner failed to inspect".

10. CenterPoint Energy agrees that the Rationale test boxes should be deleted from the Standard and applicable explanatory text be included within the Guidelines and Technical Basis.

Response: Thank you for your comment.

11. The Guidelines and Technical Basis should contain specific examples for determining if a fall-in is considered inside or outside the ROW.

Response: Thank you for your comment. The SDT established the definition of a ROW and a fall-in resulting from vegetation would be determined through investigation of the sustained outage.

12. CenterPoint Energy recommends modifying the Technical Reference section regarding "Selecting a Maintenance Approach" to delete the sentences beginning with, "If constraints cannot be overcome and if design clearances are sufficient..." and continuing through to, "identified early for rectification." This example may lead the public to inappropriately ask the utilities for exceptions to allow vegetation beneath the transmission lines, and it also does not address the dynamics of future modifications to the transmission lines (e.g. higher operating temperatures or new conductors) that may necessitate reduced clearances to ground, thus requiring removal of now mature vegetation. The example should not be

Organization	Yes or No	Question 1 Comment
included in a Standard intended to reduce vegetation risks to the transmission system. It is also in conflict with later statements in the Technical Reference regarding Set Objectives which emphasize maintaining access and clear lines of sight. **Response:** Thank you for your comment. This verbiage is part of an example describing a combination of strategies which may be utilized by a Transmission Owner. 13. In general, CenterPoint Energy strongly believes the proposed FAC-003-2 has gone far beyond what was contemplated by the Commission in FERC Order 693. The Commission's determination dealt with the following areas: (1) applicability; (2) inspection cycles; and (3) minimum clearances on National Forest Service lands. For instance, in Paragraph 729, the Commission states, "As proposed in the NOPR, the Commission approves Reliability Standard FAC-003-1 with no proposed modification on the issue of clearances. The Commission reaffirms its interpretation that FAC-003-1 requires sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions...." Rewriting the minimum clearances introduces a new set of confusing definitions, and further burdens the Transmission Owners with new documentation requirements while providing little, if any, benefit when compared to the Clearance 2 concept in the existing Standard.A preferred approach would be to incorporate the following few items into the existing Standard FAC-003-1: (1) the RC versus the RRO; (2) the designation of a specific inspection frequency; (3) the Gallet equation; and (4) the applicability to National Forest Service lands. **Response:** Thank you for your comment. The SDT believes the FAC 003-2 is an improvement over Version 1 and followed the SAR establishing that the SDT should revise the standard.		
Duke Energy	Yes	
South Carolina Electric and Gas	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	

Organization	Yes or No	Question 1 Comment
Individual		My Comments do not relate to the question asked, however, I saw no other place to add my comment. I would like to thank NERC for allowing the public to participate in the process of improving the reliability standard FAC-003-1. I became interested in Vegetation Management requirements for Transmission Lines, after Con Edison clear cut the ROW behind my home. I appreciate the importance of safe and reliable electrical service, and recognize how an effective TVMP contributes to this goal. In this whole process, what has dispirited me the most, is the inaccurate information being conveyed about why the clear cutting was necessary and, the causes of the August 14th, 2003 blackout. The narrative goes something like..”a tree falling onto transmission lines caused the black out of 2003.” I find it harmful because it misdirects the focus from the grid’s short fallings, and impedes upgrading the system to improve reliability. I found this same philosophy in the initial pages of CN Utility’s document, UTILITY VEGETATION MANAGEMENT FINAL REPORT MARCH 2004. It suggests that had the trees been adequately maintained, the blackout would have most “likely” not happened. Now I am aware of the qualification of the word “likely,” but the document is heavily weighted on the contribution of tree contact to the blackout. We know that de-regulation and the physical nature of A.C. current had more to do with the causes of the blackout, than tree contact. The timeline shows a range of cascading system failures that created the catastrophic event. The trouble began at 1:58 p.m. when First Energy generating plant in Eastlake, Ohio, shuts down. At 3:06 p.m. a First Energy 345-kV transmission line fails. As a result, at 3:17 p.m voltage dips temporarily on the Ohio portion of the grid. Controllers take no action, but power shifted onto another power line, overloading it and, causing it to sag into a tree and go offline at 3:32 p.m. Mid West ISO and First Energy controllers fail to inform system controllers in nearby states. At 3:41 and 3:46 p.m., two breakers connecting First EnergyÊ¼s grid with American Electric Power are tripped. 4:05 p.m., a sustained power surge on some Ohio lines signals more trouble building. At 4:09:02 p.m., voltage sags deeply, as Ohio draws 2 GW of power from Michigan. 4:10:34 p.m., many transmission lines trip out, beginning in

Organization	Yes or No	Question 1 Comment
		Michigan and then in Ohio, blocking the eastward ï¬‚ow of power. Generators go down, creating a huge power deficit, in seconds, power surges out of the East, tripping East coast generators, and the rest is history. The U.S.-Canada Power System Outage Task Force: Final Report on Implementation of Recommendations, September 2006, states that "Inadequate reactive supply was a factor in most of the events." and "the assumed contribution of dynamic reactive output of system generators was greater than the generators actually produced, resulting in more significant voltage problems." The backup generators were not adequate to handle the amperage load or voltage needed. A lack of coordination of System Protection Programs(relays tripping), inadequate communication between Utilities/TOs, and lack of "training of operating personnel in dealing with severe system disturbances" are all the causes for the blackout. With respect to vegetation management, the findings from The U.S.-Canada Power System Outage Task Force: Final Report on Implementation of Recommendations, September 2006, clearly did not intend for transmission owners to develop a one-size-fits-all standard. The Energy Policy Act of 2005, initiated NERC to draft and adopt the standard FAC-003-1. When I read through the standard, it all seems very reasonable. I can understand the stiff penalties for noncompliance because it seems, like an easy fix, compared to the necessary, major changes in infrastructure. The principles further outlined in ANSI A300 VII, and "Best Practices" IVM, seem very reasonable too. There is mention of the environment, property owners, even proper pruning techniques. The wire zone clearance of 10 feet and, allowing low growing compatible vegetation in the boarder zone, seems to retain more vegetation, than remove. However, in practice, the TOs are simply clear cutting the ROW, with no regard for the enviroment, the trees that they are cutting, or the abutting properties. It took Con Edison 2 1/2 half days to clear 450 tress form behind our home. We are now forced to see and hear 93,000 cars a day from the Sprain Parkway. Following the clearing, our real estate broker dropped the asking price by 30%. The house remains empty and unsold. Apparently, no one is interested in spending 32,000K a year in property taxes to look at transmission towers/lines and live on a highway. This has been

Organization	Yes or No	Question 1 Comment
		devastating to our family, and thousands of others in Westchester County. They removed a buffer of trees that were 150 feet away from wires and towers, on a downward slope. These trees would have never made contact with conductors. Con Edison's defense is that they did it because it was in their right to. Moreover, they use the NERC fine structure to defend their behavior.I went through the Notice of Penalties that NERC has issued from 6/2/08-2/01/11. Out of 646 Notice of Penalties, 1700 violations were sited, 36 out of 1700 penalties were issued for violations to the FAC- 003-1 standard. Some NOPs had multiple violations-18 R1 violations were cited and 29 penalties were issued for R2 violations. Out of the 29 R2 penalties, 20 involved tree contact. Some outages were caused by sagging wires, some were caused by arcing electricity looking for a ground fault, but none were caused by a tree falling onto the transmissions wires. The numbers should put into perspective how immaterial the problem of tree contact really is. Think about it... 20 out of 1700 involved tree contact, and none of then resulted in a sustained outage. That means 1680 violations were issued due to other system failures. To use these penalties as an excuse is a complete over exaggeration. What is missing from the standard and the fine structure, are penalties for over cutting and violations to other stipulations, such as proper communication, training, and aftercare of the affected areas. The problems that have arisen from current TVMP activities being executed nationally on our ROWs, is not a public perception problem. Rather, TOs are not complying with standards that are meant protect the environment and they are not respecting the property rights of the neighboring homeowners. I appreciate the opportunity to share my views, and would take any opportunity to further participate in protecting the rights of property owners, and the environment, while working to secure safe and reliable electrical service. Most respectfully, Amy M Kupferberg - Utility Whisperer
Response: The SDT thanks you for your comments. You raise a host of issues regarding the operations of electric transmission systems as well as recounting the blackout of 2003. We agree there seems to be wide public opinion of what actually was the cause of the blackout. Relative to your recommendations for our team, we note that appropriate NERC standards contain requirements regarding training and communications among		

Organization	Yes or No	Question 1 Comment
other things. For example, requirement R4 of this standard contains language which requires communication when certain vegetation conditions are discovered. As you know training and communications were just two of the many issues addressed in the blackout report. In response to your comment "What is missing from the standard and the fine structure, are penalties for over cutting and violations to other stipulations, such as proper communication, training, and aftercare of the affected areas," this Standard is meant to define what needs to be accomplished to achieve reliability; it is up to the Transmission Owner to perform the vegetation maintenance in a manner to accomplish that goal consistent with applicable environmental concerns and local regulations.		
Consolidated Edison Company of New York, Inc. - Transmission Line Maintenance	Yes	
USACE	Yes	
CECD	Yes	
Entergy Services, Inc	Yes	The revised Glossary definition of ROW helps to clarify the intent of what is expected and/or considered ROW stipulations. This is a beneficial addition/clarification.
Response: The SDT thanks you for your comments.		
Orange and Rockland Utilities, Inc.	Yes	
National Grid	No	The revised ROW definition emphasizes the ROW width needed to operate the transmission line(s). It is National Grid's interpretation that the width established when the line was constructed is the width to be maintained. This width is documented in engineering drawings, per-2007 vegetation records or blow-out standards. This definition does not imply that danger tree rights beyond the constructed and maintained width are incorporated in the definition; therefore fallins - from

Organization	Yes or No	Question 1 Comment
		outside the ROW but within within an area with danger tree rights would not be considered fallin-ins from within the ROW. National Grid would like the SDT to comment on this interpretation in its response to these comments.
Response: The SDT thanks you for your comments. Your interpretation is consistent with the intent of the definition that the SDT provided. However the definition includes a series of options that give the Transmission Owner latitude in establishing ROW width. It does not require selecting a single method for its system. This phrase in the definition allows a TO to use its internal engineering standards or the general engineering standards that were in effect when the line was constructed to determine the ROW width. The SDT has limited the definition of Right-of-Way to a corridor of land with a defined width to operate a transmission line. This does not include danger tree rights.		
Western Electricity Coordinating Council	Yes	
Georgia Transmission Corp.	Yes	
Northern Indiana Public Service Company	Yes	

2. **In R1 and R2 and their associated VSLs, the SDT added the phrase "in order of increasing severity" and added the sentence "The types of encroachments are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO's vegetation maintenance program." to the Rationale boxes for R1/R2. Do you agree? If answer is no, please explain.**

Summary Consideration: 32 of the 38 responses agreed with the changes. The SDT made changes to the footnotes in response to 4 requests. Three of the "yes" response comments included positive references to the improved clarity, alignment with results based standards, reinstatement of Category 3 outages and the importance of investigations which will be necessary to categorize violations across the various VSLs.

The disagreements included concerns over the relationships between the VSLs and language in requirements. The SDT revised the language in the Rationale box to explain the program performance relationships between types of encroachments, faults and outages, and various types of failed maintenance, and how the various types of failed maintenance have historically been associated with known vegetation related events.

In response to a request to exchange the order of severity levels of the failure to maintain vegetation to prevent encroachments from blowing together versus fall-ins, the SDT explained that the blowing together is considered a higher severity level of failed maintenance since the sway of the conductor is in most cases more determinable and less variable than the more complex geometry associated and numerous variables associated with fall-ins.

In response to a comment that there was no need for R1 and R2, the SDT explained that removal of R1 and R2 could be viewed as lessening the reliability of the standard.

One comment recommended that the standard include language to allow any encroachment found and removed, absent a Fault or Sustained Outage, to not be considered a violation. The SDT noted that the MVCD is a component that must be considered in the "building block" approach inherent in the standard, and as such, any encroachment inside the MVCD indicates a significant failure in overall vegetation program approach.

One comment requested a return to the Clearance 1 in the existing standard to support work that is resisted by property owners and other parties that do not want vegetation to be adequately maintained. The SDT referenced the problem associated with a fill-in-the-blank requirement, and explained how this standard does not preclude a utility from removing or pruning vegetation well beyond the MVCD, but primarily focuses on determining when a violation occurs. The SDT asserts that vegetation maintenance must address the many variables that exist such as growth rates, vegetation maintenance cycles, conductor sag and sway, etc. that could result in an encroachment of the MVCD which would be a direct violation of the standard. The vegetation program must factor in delays and/or mitigation measures associated with stakeholder concerns, but must clearly communicate the need for maintenance to ensure strict compliance with this zero-tolerance standard.

Organization	Yes or No	Question 2 Comment
SERC Vegetation Management sub-committee	Yes	
Hydro One Networks	Yes	
Northeast Power Coordinating Council	Yes	
Platte River Power Authority Substation Maintenance Group	Yes	
Bonneville Power Administration	Yes	BPA prefers the stratified levels of violation severity presented in the table for R1 and R2.Foot note #2 on page 8 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. What specifically does this phrase refer to?Foot note #4 on page 12 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. What specifically does this phrase refer to?

Response: The SDT thanks you for your comments.

The SDT has changed footnote 2 to read as follows:

This requirement does not apply to circumstances that are beyond the control of a Transmission Owner subject to this reliability standard,

Organization	Yes or No	Question 2 Comment
including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW. The SDT has changed footnote 4 (now footnote 6 in the revised standard) to read as follows: Circumstances that are beyond the control of a Transmission Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or an applicable regulatory body.		
NERC Staff	No	The sentence was added to the rationale but the phrase "in order of increasing severity" is not in the requirement or their associated VSLs. NERC staff does not support the language in the rationale box which differentiates the VSL based on skill level of maintenance personnel rather than the impact to reliability of the encroachment. The VSL should be based on whether or not the owner managed the vegetation to prevent encroachment and therefore be binary. See additional comments submitted separately regarding combining R1 and R2.
Response: The SDT thanks you for your comments. VSLs should not be assigned based on the impact to reliability, as is proposed by the commenter. NERC's VSL Guidelines state the following regarding VSLs: "This is not the same as saying that the requirement is really important and any noncompliance would have an adverse reliability impact – **the impact to reliability should be addressed through the VRF, not the VSL."** However, the SDT has made changes to reword the rationale in R1 and R2 to further explain how program performance must successfully account for the relationships between types of encroachments, faults and outages, various types of failed maintenance, and how the various types of failed maintenance have historically been associated with known vegetation related events.		
Pepco Holdings Inc and Affiliates	Yes	
FirstEnergy	No	For the Requirement R1 and R2 VSLs, we suggest that the proposed Moderate (fall-ins) and High (blowing together) VSL be interchanged. We believe that fall-ins are more severe encroachments than blowing together and the categories listed in the compliance section support this point.

Organization	Yes or No	Question 2 Comment
		Category 1 (grow-ins) is most severe, followed by Category 2 & 3 (fall-ins) and Category 4 (blowing together).
Response: The SDT thanks you for your comments. The choice of the VSL for the fall-ins versus the blowing together was made by the SDT using logic in the language in the rationale text box for R1: "The types of failure to manage vegetation are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO's vegetation maintenance program, since the encroachments listed require different and increasing levels of skills and knowledge and thus constitute a logical progression of how well, or poorly, a TO manages vegetation relative to this Requirement."		
Dominion Electric Market Policy	Yes	
Southern Company Transmission	Yes	
Arizona Public Service Company	No	This is a reliability standard and the TO should know what its clearance needs are at all rated conditions, especially considering today's technology. If the TO manages to this standard there is no need for R1 and R2.
Response: The SDT thanks you for your comments. Elimination of R1 and R2 would be considered as a lessening of the standard.		
Salt River Project	Yes	
Tampa Electric Company	Yes	Adds clarity to the VSL from an audit perspective, this is an improved description to the Standard.
Response: The SDT thanks you for your comments.		
NextEra Energy	Yes	Although NextEra Energy Inc. (NextEra), including Florida Power & Light Company, agrees with the changes referenced for R1 and R2, NextEra is concerned that the exemptions identified in footnote

Organization	Yes or No	Question 2 Comment
		2 for "...arboricultural activities or horticultural or agricultural activities...," and similar language in footnote 4, are too broad. For example, this language appears to include an exemption for a landowner, who, during arboricultural activities or horticultural or agricultural activities, causes a vegetation contact with a transmission line (e.g., cutting or lifting a tree into a transmission line). This places the Transmission Owner in the difficult position of a landowner arguing it is exempt from a controllable risk. Thus, the "...arboricultural activities or horticultural or agricultural activities..." references should be removed from footnote 2, and the similar language in footnote 4
Response: The SDT thanks you for your comments. The SDT made the suggested changes.		
SDG&E	Yes	
ASSET MANAGEMENET	Yes	
Hydro-Quebec TransEnergie (NCR07112)	Yes	
Kansas City Power & Light	No	These proposed Requirements, Measures and Violation Severity Levels as written do not give credit to the Transmission Owners for effectively monitoring their systems and taking appropriate actions in regard to vegetation clearing. Why does it make sense to punish and penalize a Transmission Owner for discovering an encroachment when they take the appropriate actions to remedy the condition before any facility outage occurs that results in compromising the reliability of the Bulk Electric System? These Requirements, Measures and VSL's should recognize the good practices of effective response to a vegetation condition and penalize ineffective response. Recommend the SDT consider including appropriate language to recognize effective remedial actions by Transmission Owners and by doing so, recognize effective efforts instead of punishing them. In addition, proving encroachments have not occurred will pose audit challenges in determining that encroachments have not occurred for the Auditors as well as Registered Entities. If no encroachments occur, then there is nothing to report or record. This is a weak platform to stand

Organization	Yes or No	Question 2 Comment
		compliance on. Facility interruption events caused by vegetation contacts is definitively measurable and recordable. Recommend the SDT reconsider the concept of compliance with FAC-003 on the basis of sustained outages and remove the references regarding encroachments only. Recommend the SDT remove the LOWER VSL language from Requirements R1 and R2 and revise the Requirements and Measures to reflect the same.
Response: The SDT thanks you for your comments. The MVCD was established as a beginning of a series of "building blocks" for a good program. R3 requires that a TO add to MVCD distances with further considerations for the variables of conductor movement and the variables associated with vegetation growth when designing the TO's overall vegetation management approach(s). The net result of this "building block" approach is the management of vegetation at clearance distances much greater than the MVCD distances. Other related requirements of this "Defense in Depth" Standard serve to address any number of scenarios which may arise or hinder the TO's ability to always strictly adhere to the management approach(s) established within R3. Thus the other requirements of this Standard provide the latitude for "appropriate actions to remedy the condition" without penalty. Further, it is obvious that trees which have encroached inside of the MVCD are clear evidence of a failed vegetation management program.		
Manitoba Hydro	Yes	
Central Maine Power Company - IberdrolaUSA	Yes	
BC Hydro	Yes	
American Transmission Company, LLC	Yes	
American Electric Power	No	American Electric Power believes that the phrase "arboricultural activities or horticultural or agricultural activities" was mistakenly introduced into Footnotes 2 and 4, and should be deleted from both footnotes. If the phrase remains in the Standard, it may empower orchard growers, landowners and others to plant trees on the right of way and challenge Transmission Owners'

Organization	Yes or No	Question 2 Comment
		rights to perform maintenance on the presumption that the standard will exempt the TO from violating the outage or encroachment requirements.
Response: The SDT thanks you for your comments. The SDT made the suggested changes.		
Baltimore Gas and Electric Co.	Yes	
TVA	Yes	
Niagara Mohawk Power Corporation (dba National Grid)	Yes	
CenterPoint Energy	Yes	
Duke Energy	Yes	We agree with the drafting team’s approach, and also agree with reinstating reporting of Category 3 (Fall-ins from outside the ROW) in the Additional Compliance Information section. The SDT responded to comments submitted with the last ballot that:”Zero tolerance for vegetation caused outages is a stated goal of FERC and NERC as it relates to this standard. This policy is part of FAC-003-1 and in concept did not change with the proposed version. The SDT recognizes this concern and has developed gradation taking into account line criticality in VRF’s and type of outage not contained in the current version FAC-003-1. Finally, it is also important to note that each and every incident or potential violation is investigated and addressed based on the specific circumstances surrounding the particular event. These investigations should necessarily take into consideration and recognize the utility's individual efforts in responding to an encroachment situation.” In addition, we believe that clarifying changes need to be made to footnotes 2 and 4. Clarify footnote 2 by removing the phrase “arboricultural activities or horticultural or agricultural activities” and replacing it with the phrase “installation of”. Similarly, clarify footnote 4 by removing the phrase “arboricultural, horticultural or agricultural activities”, and replacing it with the phrase “or human

Organization	Yes or No	Question 2 Comment
		activities such as installation, or removal or digging of vegetation.”
Response: The SDT thanks you for your comments. The SDT made the suggested changes to remove references to arboricultural, horticultural or agricultural activities from the footnote 2, but did not adopt the suggestion for the new footnote 6 which replaces the footnote 4 to which you refer” because that footnote 4 is concerned with completing the annual work plan, The SDT does not envision that actions by property owners such as installation, or removal or digging of vegetation as a valid impediment to completion of the annual work plan. However this term is relevant in R1 and R2 and as such is within foot note 2 because such actions do occur from time to time without the transmission Owner’s knowledge and do then result in conditions that could lead to encroachments and outages before the Transmission Owner has the opportunity to rectify the condition.		
South Carolina Electric and Gas	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	This is more in alignment with a results-based reliability standard.
Response: The SDT thanks you for your comments.		
Individual		
Consolidated Edison Company of New York, Inc. - Transmission Line Maintenance	Yes	
USACE	Yes	

Organization	Yes or No	Question 2 Comment
CECD	Yes	
Entergy Services, Inc	Yes	
Orange and Rockland Utilities, Inc.	Yes	
National Grid	Yes	
Western Electricity Coordinating Council	Yes	
Georgia Transmission Corp.	Yes	
Northern Indiana Public Service Company	No	While there are some enhancements to the organization and content of the standard such as the addition of the Guidelines and Technical Basis section, clarification of what constitutes evidence of compliance, and tailoring of VSL severity levels for the requirements based on the risk each poses to the likelihood of contributing to a cascade, too many elements present in FAC-003-1 and which are vital to preventing vegetation caused outages and maximizing system reliability, have been eliminated from FAC-003-2. Specifically, the elimination of concrete, declared and audited clearance standards between vegetation and conductors (the existing Clearance 1 and Clearance 2 (R1.2)) Requirements) in the revised standard is a major defect that will decrease system reliability. It has been indispensable for NIPSCO when communicating with stake holders (governments, interest groups, land owners, the public, etc.) to point to these clearance standards to give credibility and support to the kind of tree removal and trimming that is necessary to achieve the stated objective of zero preventable tree caused outages. Without these declared clearance standards in the NERC standard, utility vegetation managers will constantly be challenged by stake holders to show them that such work is required rather than an elective choice on the utility's part. One of the key lessons learned from the 2003 blackout and First Energy's overgrown ROW tree

Organization	Yes or No	Question 2 Comment
		problem was that individual land owners, local governments, and interest groups will exert pressure on the utility to only do the minimum amount of vegetation management. Without external and enforceable Vegetation Clearance Standards and by returning to a pre-2003 regime where the extent of vegetation clearing is left to the individual discretion and pressures at each utility, there is no doubt that tree clearance conditions will deteriorate over time and put system reliability at greater risk of vegetation contact.

Response: The SDT thanks you for your comments. At the request of FERC in Order 693, the SDT was asked to eliminate the fill-in-the-blank clearance requirements that are currently in FAC-003-1. A proven Engineering calculation was utilized to determine when a transmission line could spark over to vegetation without direct contact. Based on this calculation, each utility must determine what clearance levels need to be maintained as part of their TVMP. The current version does not preclude a utility from removing or pruning vegetation well beyond the MVCD, it just establishes a line in the sand that determines when a violation occurs. Individual TOs must establish a program that addresses the many variables that exist such as growth rates, vegetation management cycles, conductor sag and sway, etc. that could result in an encroachment of the MVCD which would be a direct violation of the standard. Establishing a specific clearance value to be attained during vegetation management activities is too prescriptive and is in direct conflict with the Results-Based Standard initiative that the SDT is currently implementing. Each TO must factor in delays and/or mitigation measures associated with stakeholder concerns but must clearly communicate the challenges with maintaining strict compliance with this zero-tolerance standard.

3. In response to comments received regarding the term “investigation” in M1/M2, the SDT substituted “confirmation…by the Transmission Owner..” in its place, among other minor edits to these measures. Do you agree? If answer is no, please explain.

Summary Consideration: 34 of the 40 comments agreed with the change. One of the affirmative comments noted the need to make a minor change in the Guidelines and Technical Basis to assure conformance with the standard language; that change was made.

One commenter questioned what would compel an entity to document and report outages. The SDT feels that this issue is addressed by the NERC Sanctions guidelines.

It was noted that the last two paragraphs in M1 and M2 were not really measures and should be addressed in the requirements. The requirements now include this language in footnote 3.

Two commenters wished to include language to exempt brief encroachments into the MVCD due to falling trees. The SDT chose not to make that change due to concerns raised by regulatory observers.

One commenter felt that a violation should occur for any calculated potential for an MVCD encroachment. The SDT noted that the MVCD is a beginning of a series of “building blocks” for a program to ensure reliability within the line’s rating and all rated electrical operating conditions. R3 requires that a TO add to MVCD distances with further considerations for the variables of conductor movement and the variables associated with vegetation growth when designing the TO’s overall vegetation management approach(s). Additionally there is a “Defense in Depth” in this Standard to address any number of scenarios which may arise or hinder the TO’s ability to always strictly adhere to the management approach(s) established within R3. Thus the other requirements of this Standard provide the latitude for appropriate actions to remedy the condition without penalty.

One comment replied that there was no value to the measure due to the lack of reference to a violation for any calculated potential MVCD encroachment. The SDT pointed again to requirement R3 which requires this to be addressed in the maintenance strategies in R3.

One commenter suggested to delete the reference to measures in the evidence retention section; the SDT chose to retain the existing language.

Organization	Yes or No	Question 3 Comment

Organization	Yes or No	Question 3 Comment
SERC Vegetation Management sub-committee	Yes	
Hydro One Networks	Yes	
Northeast Power Coordinating Council	Yes	
Platte River Power Authority Substation Maintenance Group	Yes	
Bonneville Power Administration	Yes	
NERC Staff	No	Concur with restating as mentioned above. Other issues remain regarding data reports indicating no sustained outages or real-time observations. These measures appear to indicate that if the outages or real-time observations are not documented then an encroachment didn't occur. What will compel an entity to document these occurrences? In addition, the last two paragraphs of the Measure are not really measures. They would be better served as part of the Requirement.
Response: The SDT thanks you for your comments. The issue of how does one prove that an event did not occur is problematic. A TO must document the inspections it completes. If an inspection does not note an encroachment then none was observed. The NERC Sanction Guidelines provide adequate sanctions for the dishonest. The SDT agrees that the last two paragraphs are not measures and would belong in the requirement. The SDT has moved them to the requirement as footnotes.		
Pepco Holdings Inc and Affiliates	Yes	

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td>FirstEnergy</td><td>Yes</td><td></td></tr>
<tr><td>Dominion Electric Market Policy</td><td>Yes</td><td></td></tr>
<tr><td>Southern Company Transmission</td><td>No</td><td>We would recommend the middle paragraph of M1 and M2 be revised as follows: “If a later confirmation of a Fault by the TO shows that vegetation encroachment within the MVCD has occurred from vegetation growing into or blowing into the conductor within the ROW, this shall be considered the equivalent of a Real-time observation. Brief encroachments caused by a falling tree going through the MVCD is not considered an encroachment.”</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comments. The SDT is sympathetic to your concern. In fact, the SDT had originally crafted language similar to that which you suggested. However, due to concerns expressed by regulators and others, the exemption for encroachment violations due to falling vegetation from inside the right of way was removed.</td></tr>
<tr><td>Arizona Public Service Company</td><td>No</td><td>The TO should be managing for reliability. The system is not static, like vegetation it moves and changes over time and that fluctuation should be taken into account to maintain reliability at all rated conditions.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comments. The SDT agrees with your statement, and in that vein, the MVCD was established as a beginning of a series of “building blocks” for a program to ensure reliability within its rating and all rated electrical operating conditions. R3 requires that a TO add to MVCD distances with further considerations for the variables of conductor movement and the variables associated with vegetation growth when designing the TO’s overall vegetation management approach(s). The net result of this “building block” approach is the management of vegetation at clearance distances much greater than the MVCD distances. Other related requirements of this “Defense in Depth” Standard serve to address any number of scenarios which may arise or hinder the TO’s ability to always strictly adhere to the management approach(s) established within R3. Thus, the other requirements of this Standard provide the latitude for appropriate actions to remedy the condition without penalty. Further, trees which have encroached inside the MVCD are evidence of a deficiency in vegetation maintenance.</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
Salt River Project	Yes	
Tampa Electric Company	Yes	Confirmation allows for the potential of a greater number of "action items" than just investigation.
Response: The SDT thanks you for your comments. We agree that confirmation is necessary before an event is determined to be vegetation related.		
NextEra Energy	Yes	
SDG&E	Yes	
ASSET MANAGEMENET	Yes	
Hydro-Quebec TransEnergie (NCR07112)	Yes	
Kansas City Power & Light	Yes	
Manitoba Hydro	Yes	
Central Maine Power Company - IberdrolaUSA	Yes	
BC Hydro	Yes	
American Transmission Company, LLC	Yes	
American Electric Power	No	For increased clarity, AEP offers the following change to the second paragraph of M1, as well as the

Organization	Yes or No	Question 3 Comment
		second paragraph of M2. The original text “If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation” should be replaced with ““If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation growing into or blowing together with the conductor within the ROW, this shall be considered the equivalent of a Real-time observation. A brief encroachment caused by falling vegetation passing through the MVCD is not considered an encroachment in this requirement”.
Response: The SDT thanks you for your comments. The SDT is sympathetic to your concern. In fact, the SDT had originally crafted language similar to that which you suggested. However, due to concerns expressed by regulators and others, the exemption for encroachment violations due to falling vegetation from inside the right of way was removed.		
Baltimore Gas and Electric Co.	No	M1 & M2 bullet: “Real-time observation of any MVCD encroachments.” implies that real-time observation of vegetation encroachment ensures reliable operation the Bulk Electric System. The reliability standard objective states;”To improve the reliability of the electric Transmission system by preventing those vegetation related outages that could lead to Cascading.”However, real time observation of current operating conditions provides no assurance that vegetation will not lead to outages since it doesn’t take into consideration the full conductor range of motion including maximum sag. BGE recommends removing the language. If an inspector finds vegetation encroaching into the MVCD during a visual inspection he / she should immediately initiate an Immediate Threat Notification. Therefore, this measure has no value.
Response: The SDT thanks you for your comments. The SDT agrees with your statement and in that vein, the MVCD was established as a beginning of a series of “building blocks” for a program to ensure reliability within its rating and all rated electrical operating conditions. R3 requires that a TO add to MVCD distances with further considerations for the variables of conductor movement and the variables associated with vegetation growth when designing the TO’s overall vegetation management approach(s). The net result of this “building block” approach is the management of vegetation at clearance distances much greater than the MVCD distances. Other related requirements of this “Defense in Depth” Standard serve to address any number of scenarios which may arise or hinder the TO’s ability to always strictly adhere to the management approach(s)		

Organization	Yes or No	Question 3 Comment
established within R3. Thus the other requirements of this Standard provide the latitude for appropriate actions to remedy the condition without penalty. Further, trees which have encroached inside the MVCD are evidence of a deficiency in vegetation maintenance.		
TVA	Yes	
Niagara Mohawk Power Corporation (dba National Grid)	Yes	
CenterPoint Energy	Yes	
Duke Energy	Yes	However, this change was not completely made in paragraph five of the Guideline and Technical Basis document. There the phrase “an investigation” should be replaced by the phrase “a later confirmation”
Response: The SDT thanks you for your comments. The SDT made the suggested change.		
South Carolina Electric and Gas	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	
Individual		
Consolidated Edison Company of New York, Inc. - Transmission Line	Yes	

Organization	Yes or No	Question 3 Comment
Maintenance		
USACE	Yes	
CECD	No	Suggested Modification to the Measure - "If an after-the-fact analysis of a Fault by the Transmission Owner determines that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of observing an encroachment in Real-Time." CECD would also like to comment on the Evidence Retention section, as it relates to Measures. The Evidence Retention section states that the Transmission Owner retains data or evidence to show compliance with Requirement R1, R2, R3, R5, and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years...." Measures provide examples of evidence that a Transmission Owner can produce to show compliance with the associated Requirement but are not separate Requirements to be managed so reference to Measures should be deleted from the Evidence Retention section of the standard.
Response: The SDT thanks you for your comments. The SDT prefers to keep the existing language, which has been widely accepted by industry, since it is substantially the same as you suggest. With respect to the Evidence Retention section: The NERC evidence retention guidelines provided to SDTs recommend including a reference to the associated requirements and measures.		
Entergy Services, Inc	Yes	
Orange and Rockland Utilities, Inc.	Yes	
National Grid	Yes	
Western Electricity	Yes	

Organization	Yes or No	Question 3 Comment
Coordinating Council		
Georgia Transmission Corp.	Yes	
Northern Indiana Public Service Company	Yes	

4. **In response to comments received that requirement R3 is unclear with respect to intent, the SDT added "maintenance strategies". Do you agree this clarifies the intent? If answer is no, please offer alternative language.**

Summary Consideration: 36 responses were in agreement, 2 disagreed with no comments and 2 disagreements included comments.

A concern was raised with regard to using the MVCD as a distance "to manage a vegetation program" and asked the SDT to provide a buffer distance. The SDT explained that the MVCD was established as a beginning of a series of "building blocks" for a program to ensure reliability within its rating and all rated electrical operating conditions. R3 requires that a TO add to MVCD distances with further considerations for the variables of conductor movement and the variables associated with vegetation growth when designing the TO's overall vegetation management approach(s). The net result of this "building block" approach is the management of vegetation at clearance distances much greater than the MVCD distances. Other related requirements of this "Defense in Depth" Standard serve to address any number of scenarios which may arise or hinder the TO's ability to always strictly adhere to the management approach(s) established within R3. Thus the other requirements of this Standard provide the latitude for appropriate actions to remedy the condition without penalty. Further, trees which have encroached inside the MVCD are evidence of a deficiency in vegetation maintenance. A performance based standard is not prescriptive in nature but gives guidance to a TO on "what" to accomplish rather than "how" to accomplish it.

Another agreeable response requested R5 and R7 to include a relationship between the document that is developed for maintenance strategies and the annual work plan. The SDT explained that the references to the work plan in R5 and R7 are sufficient. The SDT considers maintenance strategies and work plans to be separate functions. Avoiding the reference to the work plans in R3 minimizes confusing the two functions.

One disagreement stated that the term "maintenance strategies" was not helpful and recommends the following: "Each Transmission Owner shall have a documented vegetation management plan that includes maintenance strategies, procedures, processes, and specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that include(s) the following:" The SDT notes that Requirement 3 is a results-based competency requirement and that having a TVMP as required in version 1 is simply a matter of having documentation, but there was no stipulation or concern for the quality of the TVMP as called for by version 1. In R3 of the revised Standard, the aspect of quality is introduced. The Transmission Owner must show that it has maintenance strategies in place that will logically keep vegetation from encroaching into the MVCD.

Another disagreement stated that the TVMP shall demonstrate the TO's ability to manage the system at all rated conditions to maintain reliability. The SDT agrees that this is the purpose of R3 and referenced the language in the rationale text for R3 clarifies - "... documentation provides a basis for evaluating the competency of the Transmission Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the Transmission Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. See Figure 1 for an illustration of possible conductor locations." A TVMP is one example of an approach to which this refers.

Organization	Yes or No	Question 4 Comment
SERC Vegetation Management sub-committee	Yes	
Hydro One Networks	Yes	
Northeast Power Coordinating Council	Yes	
Platte River Power Authority Substation Maintenance Group	Yes	
Bonneville Power Administration	Yes	The TO procedures / policies and specifications shall demonstrate the TO's ability to manage the system at all rated conditions to maintain reliability.BPA believes that the intent is clear, but the fundamental approach of using the MVCD (table 2) to manage a vegetation program is still problematic. These values are flashover distances and are way too close. This is acknowledged in a footnote to table 2 but no identification of allowable buffers/distances between energized phase conductors at rated temperatures and vegetation is discussed (this is left up the transmission owners). Clarity is needed on this topic. Setting a finite distance limit based on recognized standards, good science and risk avoidance should be done for the industry. BPA previously made this comment during the drafting of the standard. It was not addressed then, nor has it been

Organization	Yes or No	Question 4 Comment
		addressed now.
Response: The SDT thanks you for your comments. The SDT agrees with your statement, and in that vein, the MVCD was established as a beginning of a series of "building blocks" for a program to ensure reliability within its rating and all rated electrical operating conditions. R3 requires that a TO add to MVCD distances with further considerations for the variables of conductor movement and the variables associated with vegetation growth when designing the TO's overall vegetation management approach(s). The net result of this "building block" approach is the management of vegetation at clearance distances much greater than the MVCD distances. Other related requirements of this "Defense in Depth" Standard serve to address any number of scenarios which may arise or hinder the TO's ability to always strictly adhere to the management approach(s) established within R3. Thus the other requirements of this Standard provide the latitude for appropriate actions to remedy the condition without penalty. Further, trees which have encroached inside the MVCD are evidence of a deficiency in vegetation maintenance. A performance based standard is not prescriptive in nature but gives guidance to a TO on "what" to accomplish rather than "how" to accomplish it.		
NERC Staff	No	Adding the term "maintenance strategies" is not helpful in the requirement. NERC staff recommends the following: "Each Transmission Owner shall have a documented vegetation management plan that includes maintenance strategies, procedures, processes, and specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that include(s) the following:"
Response: The SDT thanks you for your comments. Requirement R3 is a results-based competency requirement. Having a TVMP as required in version 1 is simply a matter of having documentation. There was no stipulation or concern for the quality of the TVMP as called for by version 1. In R3 of the revised Standard, the aspect of quality is introduced. The Transmission Owner must show that it has maintenance strategies in place that will logically keep vegetation from encroaching into the MVCD.		
Pepco Holdings Inc and Affiliates	Yes	
FirstEnergy	Yes	
Dominion Electric Market	Yes	

Organization	Yes or No	Question 4 Comment
Policy		
Southern Company Transmission	Yes	
Arizona Public Service Company	No	The TVMP shall demonstrate the TO's ability to manage the system at all rated conditions to maintain reliability.
Response: The SDT thanks you for your comments. We agree that this is the purpose of R3. Please note the language in the rationale text for R3 clarifies - "... documentation provides a basis for evaluating the competency of the Transmission Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the Transmission Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. See Figure 1 for an illustration of possible conductor locations." A TVMP is one example of an approach to which this refers.		
Salt River Project	Yes	
Tampa Electric Company	Yes	Good addition, adds clarity and improves overall understanding of the requirement.
Response: The SDT thanks you for your comments.		
NextEra Energy	Yes	
SDG&E	Yes	
ASSET MANAGEMENET	Yes	
Hydro-Quebec TransEnergie (NCR07112)	Yes	

Organization	Yes or No	Question 4 Comment
Kansas City Power & Light	Yes	
Manitoba Hydro	Yes	
Central Maine Power Company - IberdrolaUSA	Yes	
BC Hydro	Yes	You could also include the term “maintenance standards”.
Response: The SDT thanks you for your comments. Either word could work – however since most commenters agreed with the use of the word, ‘strategies’ the SDT did not adopt the suggestion to use the word, ‘standards’.		
American Transmission Company, LLC	Yes	
American Electric Power	Yes	
Baltimore Gas and Electric Co.	Yes	
TVA	Yes	
Niagara Mohawk Power Corporation (dba National Grid)	Yes	
CenterPoint Energy	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 4 Comment
South Carolina Electric and Gas	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	This clearly defines “intent”.
Response: The SDT thanks you for your comments.		
Individual		
Consolidated Edison Company of New York, Inc. - Transmission Line Maintenance	Yes	
USACE	No	
CECD	Yes	Because Requirement 5 and 7 use the phrase annual work plan, and there is not a Requirement to develop a work plan, this Requirement should include a relationship between the document that is developed for maintenance strategies and the annual work plan.
Response: The SDT thanks you for your comments. The SDT considers the references to the work plan in R5 and R7 sufficient. The SDT considers maintenance strategies and work plans to be separate functions. Avoiding the reference to the work plans in R3 minimizes confusing the two functions.		
Entergy Services, Inc	Yes	

Organization	Yes or No	Question 4 Comment
Orange and Rockland Utilities, Inc.	Yes	
National Grid	Yes	
Western Electricity Coordinating Council	Yes	
Georgia Transmission Corp.	Yes	
Northern Indiana Public Service Company	No	

5. **The SDT added clarifying language in M7 to explain how the annual work plan percentage complete calculation is to be performed. Is this adequate? If no, please provide improved examples.**

Summary Consideration: There were 31 agreements and 8 disagreements. Seven comments noted that the question should have referenced R7 not M7. The SDT acknowledged that observation and agreed that the reference should have been R7. The SDT added the term "of applicable lines" to M7 and to the VSL's for R4, R5 and R6. The SDT also made minor changes to VSLs for R7 to conform to verbiage in R6.

One commenter agreed with R7 changes and noted "there is no requirement....that a plan is....developed." The SDT sees no reason to add such a requirement for documentation, since a fundamental precept of results-based standards is that having a requirement to complete any particularly activity also presupposes that the elements required to complete the activity are included in the requirement, even if unstated.

One affirmative comment requested that exceptions for crew performance and availability be noted explicitly: the SDT noted that while the requested condition could be listed, the list is not meant to be exhaustive, and that any modification to the work plan can be made provided it does not allow encroachment into the MVCD. The same commenter wished to include language related to derating the line to indicate that the purpose of such action would be to "ensure continued...reliability." The SDT saw problems associated with proving that a reliability contribution by a derating was in fact accomplished and chose to retain the existing language. The same commenter wished to remove Category 3 outage reporting, but the SDT sees great value in the investigation of each vegetation related outage and feels that this reporting is justified to ensure that all outages are sufficiently investigated. The same commenter requested removing the reference to "defense-in-depth" in the Background section; the SDT chose to leave this reference as is. Lastly that same commenter suggested that "promptly" could be substituted for "without intentional time delay" in R4, the SDT saw no difference in the two terms and chose to keep the existing verbiage.

A commenter suggested in lieu of the annual inspection requirement that a time interval based on growth rates be used instead. The SDT chose to retain the existing annual interval based on industry's consensus support for the one year interval in a previous posting of the Standard.

A commenter requested that "of applicable lines" be added to the requirements and VSL verbiage to clearly denote applicability within the requirements and VSL verbiage. The SDT made those changes as requested to the requirements, measures and VSLs. That same commenter requested that Category 3 outages be reported by type A & B similar to other categories. The SDT saw no value to this change since Category 3 serves its purpose without that distinction being made. The same commenter requested changes to the ROW definition; the SDT chose to retain the existing language since it has been vetted with significant industry consensus.

Another comment suggested adding reference to financial reports in the examples for reasons for modifications to the annual plan, the SDT feels that such a reference to financial conditions was inappropriate. The same commenter noted the need for clarity in the structure of the VSLs ; the SDT made those changes. The same commenter requested clarity on use of Table 2 when an entity has a voltage category not in the table - the team added language to clarify that where the TO has transmission lines operated at nominal levels not listed in Table 2, the TO should use the clearance distances based on the maximum system voltage (i.e. for a nominal system voltage of 287 kV the appropriate distances would be for a maximum system voltage of 362 kV). Two commenters requested an example be added to the Guidelines and Technical Basis section for R7, similar to the examples in R6, to clarify that the % calculations should be based on the Annual Plan as modified; the SDT added the example as requested.

Another commenter questioned the 48-hour reporting in the 12/17/2008 NERC Public Notice - NERC Compliance Process #2008-001. The SDT discussed the issue with NERC staff and did not receive any direction that it would be necessary to add this as a Requirement within the Standard

Additional comments were offered by NERC staff as a separate attachment to comments submitted with the comment form, and those responses are covered following this question.

Organization	Yes or No	Question 5 Comment
SERC Vegetation Management sub-committee	Yes	
Hydro One Networks	Yes	
Northeast Power Coordinating Council	No	There is no percentage language in M7. Is it R7 that is being referred to?
Response: The SDT thanks you for your comment. The SDT meant to refer to R7.		

Organization	Yes or No	Question 5 Comment
Platte River Power Authority Substation Maintenance Group	Yes	
Bonneville Power Administration	Yes	
NERC Staff	Yes	Actually, R7 contains the clarifying language. It should be noted that although R7 indicates the TO shall complete 100% of the VM work plan, there is no requirement in this draft that a plan is actually developed.
Response: The SDT thanks you for your comments. The SDT meant to refer to R7, not to M7. As to the seeming lack of an actual requirement for a work plan, the SDT asserts that a fundamental precept of results-based standards is that having a requirement to complete any particularly activity also presupposes that the elements required to complete the activity are included in the requirement, even if unstated.		
Pepco Holdings Inc and Affiliates	Yes	
FirstEnergy	Yes	Although we generally agree with Requirements R7 and its measure M7, we suggest adding clarifying wording to bullet 4 which states "Crew or contractor availability/ Mutual assistance agreements". In addition to availability, contractor performance may be another issue that requires modification to the work plan. We suggest adding another bullet that reads "Crew or contractor performance". The rationale behind this addition is to address poor safety, productivity and/or quality issues with a crew or contractor assigned to perform vegetation management.FirstEnergy provides the following additional comments and suggestions not related to the specific questions asked in this posting: 1. Requirement R5 - We appreciate this requirement which recognizes that the TO may face situations in which it is constrained from performing its vegetation management and are permitted

Organization	Yes or No	Question 5 Comment
		to seek alternative methods. However, there may be instances where the TO has exhausted all course of action to perform vegetation and must utilize other means to prevent vegetation encroachment into the MVCD. Therefore, in these instances, "continued vegetation management" as stated in the requirement is not possible, but other methods such as line deratings and deenergizing of lines may have to be used. We ask that the phrase "to ensure continued vegetation management to prevent encroachments" be changed to read “to ensure continued reliability of the BES”. 2. Compliance Section - Category 3 - We suggest removing this category from the standard. Since fall-ins from outside the ROW are not considered a violation of this standard per Requirements R1 and R2, the entity should not have to report these fall-ins. 3. Objectives - We do not believe that is necessary for the Objectives statement to include the "defense-in-depth" concept which is actually an overarching goal of results-based standards in general and not specific to FAC-003-2. We suggest removing this phrase. 4. Background Section 5 - Similar to our comment above regarding defense-in-depth in the objectives statement, this is an overarching goal of results based standard and not specific to FAC-003-2. Therefore, we suggest removing the explanation of defense-in-depth from the background section. 5. Vegetation Inspection Definition - We suggest replacing the word "hazard" with "risk". 6. Requirement R4 - We do not agree with the phrase "without any intentional time delay" and suggest it be removed. This phrase is not measurable. Also, other drafting teams have attempted to incorporate this statement but industry comments have persuaded them to remove it; for example, the Reliability Coordination drafting team (Project 2006-06) initially proposed the same phrase but later removed it in their development of the COM/IRO standards. At the very least standards development should be consistent throughout the NERC standards drafting teams. We suggest the following as wording for Requirement R7: "Each Transmission Owner shall ensure the control center holding switching authority for the applicable transmission line is promptly notified

Organization	Yes or No	Question 5 Comment
		when the Transmission Owner has confirmed the existence of a vegetation condition that can potentially cause a Fault."

Response: The SDT thanks you for your comments. The SDT considered your request to add to the acceptable reasons for modifications the bullet, "Crew or contractor performance," and observes that since R7 states "Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD)..." the bullet could be added, but the SDT did not intend the list of examples to be exhaustive and decided not to add the new bullet.

In reference to the comment 1) that the phrase "to ensure continued vegetation management to prevent encroachments" be changed to read "to ensure continued reliability of the BES," the SDT agrees that the corrective actions of de-ratings and de-energization as you suggest must be considered when vegetation cannot be maintained to prevent encroachment into the MVCD, and those examples are explicitly listed in M5. If a de-rating is used, it must be sufficient to prevent the encroachment into the MVCD. The de-rating or de-energization of the line removes the threat of an energized line and adjacent vegetation having less separation that the MVCD (i.e. less Fault probability), but the realized reliability value of those actions will depend on the events that occur while the condition persists. For these reasons the SDT retains the R5 language without changes.

In reference to the comment 2) "Compliance Section - Category 3 -...suggest removing this category from the standard," an investigation of the location of the tree with respect to the edge of the ROW for fall-ins must be made to determine whether the event represents a self-report of a violation or not. A record of those findings when the tree is found to be outside the ROW is valuable for both the Compliance Monitoring and Enforcement and the TO, should any questions later arise; therefore the SDT chose to retain the Category 3 reporting.

Regarding your comment 3) "Objectives - We do not believe that is necessary for the Objectives statement to include the "defense-in-depth" concept which is actually an overarching goal of results-based standards in general and not specific to FAC-003-2. We suggest removing this phrase." The SDT notes that the Purpose language is a general statement, and could be expanded or contracted without impacting the requirements. However, since the current language has undergone extensive debate, comment and revision the SDT sees no compelling reason to request industry to review another change at this time.

Regarding your comment 4) "Background Section 5 -.... suggest removing the explanation of defense-in-depth from the background section" The SDT notes again that the background section language is a general statement and could be expanded or contracted without impacting the requirements. However, since the defense-in-depth drove many of the changes in the standard the SDT thinks this section is relevant and should be retained.

Organization	Yes or No	Question 5 Comment
Regarding your comment 5) “suggest ...for Requirement R7(actually R4): "Each Transmission Owner shall ensure the control center holding switching authority for the applicable transmission line is promptly notified when the Transmission Owner has confirmed the existence of a vegetation condition that can potentially cause a Fault." The SDT has searched for but not found a time limit more suitable than “without intentional time delay.” An extensive list of event scenarios between the time that a condition is observed and the time it is reported can be studied. In the final analysis the intent is for the notification to be made to allow time for the control center to take steps to maintain reliability if possible before conditions deteriorate further. “Without intentional time delay” is as sufficient and as measurable as “promptly”.		
Dominion Electric Market Policy	No	The red-line revision does not indicated changes to M7; therefore, Dominion is unable to evaluate the clarifying language identified in this question. If the SDT meant to reference R7, we agree that the clarification is adequate.
Response: The SDT thanks you for your comments. The SDT means to reference R7.		
Southern Company Transmission	Yes	
Arizona Public Service Company	Yes	
Salt River Project	Yes	
Tampa Electric Company	Yes	This allows flexibility for the T.O. to determine the type of “unit” used in calculating the percentage complete.
Response: The SDT thanks you for your comments.		
NextEra Energy	Yes	
SDG&E	Yes	

Organization	Yes or No	Question 5 Comment
ASSET MANAGEMENET	Yes	
Hydro-Quebec TransEnergie (NCR07112)	No	The minimum frequency of Vegetation Inspection should be based upon an average growth rates of smaller regions than all North America. Example, above the latitude of about 50 degrees North, the vegetation growth rates is limited. We think that Vegetation Inspection frequency should be relaxed to 3 years for those areas in Canada. As indicator of the minimum frequency requested in R6, we suggest to use a global vegetation index like the Normalized Difference Vegetation Index (NDVI). The NDVI has been in use for many years to measure the vigor of vegetation growth among other things. http://earthobservatory.nasa.gov/Features/MeasuringVegetation/
Response: The SDT thanks you for your comments. In FERC Order 693, para. 721, FERC stated, "The Commission continues to be concerned with leaving complete discretion to the transmission owners in determining inspection cycles, which limits the effectiveness of the Reliability Standard." The SDT established an inspection cycle at least once per calendar year and with no more than 18 months between inspections on the same ROW. There was a survey of the industry in a previous request for comments to this standard. The response to that survey is the basis for the use of the 1-year period. While there was a range of growth rates across the continent, the SDT had sufficient feedback to recommend the 1-year cycle. The inspection also would cover inspecting for fall-in threats. Please note that vegetation inspections can also be combined with other line inspections.		
Kansas City Power & Light	No	1) R7 states "Each Transmission Owner shall complete 100% of its annual vegetation work plan...". We suggest to be consistent with all other sections of the rule that it should read, "Each Transmission Owner shall complete 100% of its annual vegetation work plan for all applicable lines...". Otherwise, leaves room for interpretation to include all lines including those not defined as applicable. Also require these same revisions to row R7 of the table "Time Horizons, Violation Risk Factors, and Violation Severity Levels". 2) In the "Additional Compliance Information" section Categories 1, 2, and 4 are each defined to have an A & B component to recognize the severity level difference for "applicable transmission lines" identified versus not identified "as an element of an IROL or Major WECC Transfer Path". However, Category 3 does not separate these two scenarios however it appears that the same

Organization	Yes or No	Question 5 Comment
		distinction should apply. Additional comments:Vegetation Inspection Definition Recommend the SDT consider removing the conditional language, “that are likely to pose a hazard to the line(s) prior to the next”. Vegetation inspections are not dependent on a predisposed condition of vegetation. Suggest the SDT remove that phrase and consider the following definition:The systematic examination of vegetation conditions on a maintained transmission line Right-of-Way under the Transmission Owner’s control under a planned maintenance or inspection which may be combined with a general line inspection.
Response: The SDT thanks you for your comments. 1) The team has made the appropriate modifications, adding the reference to ‘applicable lines’ where necessary. 2) Since the Category 3 outages do not have any violations associated with their occurrences, the SDT did not see the value in reporting by type A or type B lines. 3) The SDT chooses to keep the current language because it addresses the core need to find conditions that will need correcting before the next planned maintenance or next planned inspection is performed.		
Manitoba Hydro	Yes	
Central Maine Power Company - IberdrolaUSA	Yes	
BC Hydro	Yes	You could also include other documentation such as monthly financial and program variance reports. Additional Comments Table 1: R6 definitions could be clearer. Suggested clarification: VSL Lower - Greater than 95% of annual inspections complete but less than 100% complete. VSL Moderate - Greater than 90 % of annual inspections complete but less than 95% complete VSL High - Greater than 85% of annual inspections complete but less than 90% complete VSL Severe - Less than 85% of annual inspections completed

Organization	Yes or No	Question 5 Comment
		Table 1 R7 definitions could be clearer. Suggested clarification: VSL Lower - Greater than 95% of annual work plan complete but less than 100% complete. VSL Moderate - Greater than 90 % of annual work plan complete but less than 95% complete VSL High - Greater than 85% of annual work plan complete but less than 90% complete VSL Severe - Less than 85% of annual work plan completed Table 2: This table includes a number of common nominal system voltages vs MVCD distances by altitude. However, some utilities have other non-standard voltages, in our case 287 kV, which forms a significant part of their system. It may be worthwhile for the standard to state what a utility should follow when a standard voltage class is not present - i.e. go to the next higher voltage MVCD if a particular voltage isn't in the table, or direct the utility to do its own Gallett Equation calcuations for their unique voltage class. Otherwise, different utilities may create a non-standard solution that wouldn't address the risk.
Response: The SDT thanks you for your comments. The SDT did not intend for the list of examples to be exhaustive. To the extent that financial or variance reports include evidence of the work units completed they may be useful as supportive evidence. inappropriate. The SDT used the NERC VSL Guidelines to develop the VSLs; therefore the SDT feels that the VSL's for R7 are adequate as listed. The proposed VSLs would leave some 'gaps' – for example the proposed VSLs aren't clear on what VSLs is assigned when an entity has completed exactly 95% of its inspections. Table 2 in the Standard lists both the nominal system voltages and the corresponding maximum system voltages. The clearance distances listed for each nominal system voltage were calculated using the maximum system voltage values. Therefore, where the TO has transmission lines operated at nominal levels not listed in Table 2, the TO should use the clearance distances based on the maximum system voltage (i.e. for a nominal system voltage of 287 kV the appropriate distances would be for a maximum system voltage of 362 kV). The SDT has added language to the guidelines and technical basis section to clarify this point.		
American Transmission	Yes	

Organization	Yes or No	Question 5 Comment
Company, LLC		
American Electric Power	Yes	
Baltimore Gas and Electric Co.	Yes	
TVA	No	I suggest that footnote 4 be changed by removing the reference to arbicultural, horticultural or agricultural activities.
Response: The SDT thanks you for your comments. The recommended changes have been made to footnote 4.		
Niagara Mohawk Power Corporation (dba National Grid)	No	There is currently no percentage language in M7. If they are referring to R7, then YES it is adequate.
Response: The SDT thanks you for your comments. The question should have referred to R7.		
CenterPoint Energy	No	CenterPoint Energy could not find any reference to an example percentage complete calculation for the annual work plan in the Standard for M7, in the Guideline and Technical Basis for M7, nor in the Technical Reference for M7. There was such an example for M6 which was helpful. CenterPoint Energy recommends such an example be included for M7.
Response: The SDT thanks you for your comments. The percentage complete should be based on the annual plan as modified. The SDT has changed the language in the standard to reflect more clearly that the percentage complete should be based on the plan as modified, and the following example has been added to the Guideline and Technical Basis: For example, when a Transmission Owner identifies 1,000 miles of 230 kV transmission lines to be completed in the TO's annual plan, the Transmission Owner will be responsible completing those identified miles. If a TO makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage the TO completed for the current year would be: 1000 – 100 (deferred miles) = 900 modified annual		

Organization	Yes or No	Question 5 Comment
plan, or 900 / 900 = 100% completed annual miles. If a TO only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: 1000 – 875 = 125 miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12% failed to complete.		
Duke Energy	Yes	
South Carolina Electric and Gas	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	This is directed toward R7 rather than M7.
Response: The SDT thanks you for your comments.		
Individual		
Consolidated Edison Company of New York, Inc. - Transmission Line Maintenance	Yes	The added language for the annual work plan percentage complete calculation is shown in R7 not M7 as stated in the question. In the Guideline and Technical Basis Section for Requirement R6, there is a sample calculation shown for the amount of lines the TO failed to inspect. An example should also be included for Requirement R7 since there is some confusion regarding how modifications to the work plan affect the calculation. In the Lower VSL column for R7, it states that the TO failed to complete up to 5% of its annual vegetation work plan (including modifications if any). If a TO operates 100 lines and submits a justified modification that affects 10 miles of lines, the total number of units in the final amended plan is 90 miles. When you read the VSL, it is somewhat confusing since the information in parenthesis says that the calculation 'includes' the modifications. Should it state 'excludes modifications if any' or the VSLs can simply be re-written to state that ..The TO failed to complete up to x% of the final amended plan.' Also, the VSLs in R6 and

Organization	Yes or No	Question 5 Comment
		R7 should be consistent with each other: R6 says '...TO failed to inspect 5% or less.....' and R7 says '...TO failed to complete up to 5%....' They both should use the same verbiage in each VSL whether it is 'x% or less' or 'up to and including x%.'
Response: The SDT thanks you for your comments. The percentage should be based on the plan as modified. The SDT has changed the language in the standard to reflect this more clearly.		
USACE	Yes	
CECD	Yes	
Entergy Services, Inc	Yes	The actual clarifying language seems to have been added to R7 instead of M7 (as stated above). The clarifying language provides benefit as added to R7, and should remain in R7.Additionally, we feel that, in an effort to promote consistency with the other 6 Requirements, the term "on applicable Transmission lines" should be added at the end of the first sentence of R7, as it is listed in all other R's. The first sentence of R7 currently reads: "Each Transmission Owner shall complete 100% of its annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD". We feel the first sentence should read "Each Transmission Owner shall complete 100% of its annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD on applicable transmission lines".
Response: The SDT thanks you for your comments. The first sentence does now contain the term “applicable lines”.		
Orange and Rockland Utilities, Inc.	Yes	
National Grid	No	There is currently no percentage language in M7. If they are referring to R7, then YES it is adequate.

Organization	Yes or No	Question 5 Comment
Response: The SDT thanks you for your comments. The SDT was referring to R7.		
Western Electricity Coordinating Council	Yes	We support the clarifying languae in M7However, since there is no generic "Any other Comments" section associated with this on-line comment form, we raise a question here. On December 24, 2008, NERC issued an e-mail to all Transmission Owners in which it referenced its December 17, 2008 Public Notice - NERC Compliance Process #2008-001, Vegetation-related Transmission Outage Reporting. The notice stated that: "Due to the potential severity of transmission outages caused by vegetation associated with Standard FAC-003-1, NERC is encouraging each Transmission Owner to self-report all Category 1 and Category 2 transmission outages related to vegetation to the Regional Entity within 48 hours utilizing the 48-hour vegetation reporting notice form provided by your appropriate Regional Entity."We do not see any reference to a 48-hour reporting notice in lthis version of the standard. Is this still a requirement? The only reference to reporting is in the Additional Compliance Information section and references quarterly reporting only.
Response: The SDT thanks you for your comments. The SDT is aware of the 48 hour, voluntary self-report request from NERC for outages where vegetation may be involved. The SDT also agrees with the general philosophy proposed by WECC that all requirements associated with a Standard are best served in the Standard. Also, the SDT did examine the general concept of an "investigation" type requirement. However, the SDT did not pursue this because it did not satisfy the basic rule for requirements as embedded in the Standards Process Manual, "What functional entity shall do what under what conditions to achieve what reliability objective." After the fact investigation and reporting, while important to the Compliance and Enforcement (CMEP) aspect of mandatory and enforceable Standards, does not achieve a reliability objective such that the failure to comply with the Requirement would jeopardize reliability. The SDT also notes that any useful (other than CMEP) information related to an outage that is subsequently reported under the NERC voluntary request would generally be available for industry use through TADS. Finally, the SDT did discuss the issue with NERC staff and did not receive direction that it was necessary, or desirable, to include one or more elements of the voluntary request in this Standard.		
Georgia Transmission Corp.	Yes	
Northern Indiana Public	Yes	

Organization	Yes or No	Question 5 Comment
Service Company		

Additional Comments from NERC:

In addition to the comments NERC submitted to the five questions on the official comment form, NERC staff has numerous other comments to make with regard to this Draft 5. Before that, NERC staff first wants to acknowledge the significant effort and talent that the industry brought to attempt to improve upon Reliability Standard FAC-003-1 – Vegetation Management. This Draft 5 of FAC-003-2 – Vegetation Management entailed significant industry work towards understanding the issue, compromising on proposals and attempting to reach consensus utilizing the NERC Standards Development Process. While NERC staff believes this draft represents some improvements to the existing standard, it does not believe the draft in its totality represents an improvement to the existing standard. FERC Order 693 approved the existing Vegetation Management Standard and it provided a number of directives for NERC with regard to further developing the Standard in order to improve it. Such directives and NERC comments regarding how the directives were addressed included:

- FERC Directive - Develop compliance audit procedures, using relevant industry experts, which would identify appropriate inspection cycles based on local factors. The Commission is dissuaded from requiring the ERO to create a backstop inspection cycle at this time.

  NERC Comment – Compliance audit procedures are outside the scope of the SDT and this Draft 5. Although not required by the Commission, the SDT added an annual inspection cycle to the Standard, with a maximum of 18 months between inspections. NERC believes this requirement represents an improvement to the existing Standard and does not believe it is overly burdensome on utilities.

Response: The SDT thanks you for your comments.

- FERC Directive - Remove the general limitation on lines 200kV and above to include lines that have an impact on reliability.
  - Do not reduce facilities included
  - Develop an acceptable definition for the applicability of this Reliability Standard that covers facilities that impact reliability while not unreasonably increasing the burden on transmission owners.
  - Evaluate the suggestions proposed by LPPC, APPA and Avista that regional entities should determine which facilities this standard applies to

  NERC Comment – NERC believes Draft 5 partially addresses this issue by increasing applicable facilities to IROL lines under 200kV. NERC staff is also concerned about

- The possibility that this very addition could limit a regional entity's desire to include additional lines.
- The exclusion of facilities inside the fenced area of switching stations, stations and substations. These excluded areas still pose a vegetation related outage risk and the rationale for excluding them is not compelling enough.
- The separation of IROL (any voltage level) and non-IROL (200 kV and above) Transmission Lines into separate requirements with different VRFs. NERC believes all Transmission Lines subject to this standard should be under the same requirement and associated VRFs. IROL lines are relatively few and do not warrant their own requirement. By having lower VRFs for non-IROL lines, this version of the standard is weaker than the existing standard. These two requirements should be a single requirement with high VRFs

Response: The SDT thanks you for your comments. In the guidelines provided by NERC to the drafting team, the SDT is dissuaded from writing 'fill in the blank' requirements. In version one, the team directed the RO to designate which critical lines below 200kV should fall under the standard without defining what critical meant. This is a 'fill-in-the- blank.' There is no assurance that this applicability would be applied consistency across North America. The SDT followed FERCs suggestion to take into account "…the suggestions by Progress Energy, SERC and MISO to limit applicability to lower voltage lines associated with IROL…" The team went further by including WECC transfer paths. The SDT asserts that the inclusion of both IROL lines and WECC Transfer paths addresses the comments by LPPC, APPA and Avista along with Progress Energy, SERC and MISO. The NERC Staff needs to consider that the comments all contend that each inclusion of a below 200kV line is an added burden to the rate payers. Not to give some direction to the Planning Coordinator would allow a planner to include ALL transmission lines, which would be an unreasonable burden to the rate payer. We added this language for clarity at the request of stakeholder concerns.

Neither the standard nor its original SAR were intended to cover fenced or discrete locations such as substations, which entail entirely different issues compared to linear corridors. Often substations are owned by either DPs or GOs, therefore, the TO may not have rights inside the fenced facility. The requirements in this standard would not be sufficient to include stations and switch yards. Should there be a compelling need for a vegetation standard for fenced facilities, a new SAR should be introduced.

The SDT asserts that different VRF's for IROL and non-IROL lines strengthens the reliability of the standard. Vegetation managers that do not know which lines are IROL or WECC Transfer Paths may be inappropriately limiting resources allocated to vegetation management for an IROL line or a WECC Transfer Path. A vegetation manager must ensure that the IROL lines and WECC transfer paths are absolutely clear. By correctly identifying the risk associated with an IROL line and/or a WECC Transfer Path, the standard helps to assure that appropriate resources are applied.

VRF guidelines require an analysis of impact to BES. We did that by considering the relative risk levels to the interconnected transmission system of an interruption of a non-IROL/non-Transfer Path line versus the interruption of IROL/Transfer Path lines. The fact that the PENALTY might be higher or lower DOES NOT AFFECT the strength or weakness of the Standard, since even the Medium Risk Factor value in the Base Penalty Matrix in the sanctions guidelines is $350,000 per violation per day. In both R1 and R2 of Version 2 there is zero-tolerance for encroachments, and Version 2 increases the scope to include observed encroachments without Faults, and confirmed vegetation Faults without Sustained Outages which were not clearly included in Version 1. The 1) distinction by separation of VRFs and 2) inclusion of clear language to inspect for, investigate, correct, and report to all known reliability threats will strengthen the standard.

- FERC Directive - Develop a Reliability Standard that defines the minimum clearance needed as an improvement to IEEE 516 which FERC does not believe is appropriately used for purposes of reliability and/or safety.

  NERC Comment – Draft 5 makes a change from IEEE 516 and utilizes Gallet equations for industry clearances. While NERC believes these equations are technically accurate, NERC is concerned about the usefulness of the clearances determined under this methodology as put forth in this draft. NERC is not aware of any utility which would maintain clearances as specified in this draft as it has no built in safety factor. NERC is further concerned that utilities could be mandated by courts of law to reduce existing maintained clearances to values much closer to those determined by the methodology in this draft.

Response: The SDT thanks you for your comments. As with a Transmission Owner's determination of its Clearance 1 distances under version 1 of the Standard, Requirement 3 of the revised Standard begins with the MVCD distances (just as Clearance 1 began with IEEE-516 distances) and then requires additional consideration for conductor movement, vegetation growth variables, and the utility's maintenance approach. These are essentially the same considerations required by version 1 of the existing Standard when developing Clearance 1 distances. Therefore, nothing has been "lost" in the revised Standard. In fact, the proposed Standard is better from an auditing perspective because the overall logic and rationale used by the TO in complying with the new Requirement 3 is now subject to an overall test of adequacy, competency and reasonableness. Also, informal polls conducted by the SDT show that many Transmission Owners are unsuccessful in utilizing Clearance 1 as a tool, because it is easily challenged by landowners as being an arbitrary fill-in-the-blank value set by the Transmission Owner. Further, if the Transmission Owner would cut only to Clearance 1 instead of to the full extent of its legal rights, courts could rule against the Transmission Owner for failing to exercise its full legal rights. Thus, in the revised Standard, the Transmission Owner has neither gained nor lost any tool or advantage in dealing with landowners, but the SDT asserts that the bar has been raised with regard to the adequacy of the Transmission Owner's overall vegetation management program.

- FERC Directive - Define rights-of-way to encompass the required clearance areas instead of the corresponding legal rights, and the standards should not require clearing the entire right-of-way when the required clearance for an existing line does not take up the entire right-of-way.

  NERC Comment – NERC staff believes this directive was met and is addressed in question 1 of the comment form.

Response: The SDT thanks you for your comments.

- FERC Directive – NERC should address the proposed modifications through its Reliability Standards development process.

  NERC Comment – NERC staff believes this directive was met in preparing this draft standard.

Response: The SDT thanks you for your comments.

- FERC Directive - Collect outage data for transmission outages, analyze it, and use the results of this analysis and information in the development of the Reliability Standard.

  NERC Comment – NERC staff believes more work needs to be done in this area. NERC staff believes the drafting team should consider modifying the Periodic Data Submittal to include if outages occur on Federal land.

Response: The SDT thanks you for your comments. After discussion with NERC staff, NERC has agreed to address this issue outside the work of the SDT. The SDT recommends that NERC staff consider adding a field to the TADS data to capture vegetation outages on applicable lines on federal lands.

Other Draft 5 Issues

- Removal of a formal transmission vegetation management program, of Clearance 1 and of a documented vegetation management plan.

NERC Comment – NERC does not support the removal of these items. NERC does not believe these changes represent an improvement to the standard and does not believe this existing requirement is overly burdensome to utilities. NERC does not understand why industry would not be willing to be held accountable to their vegetation management plans. NERC is concerned that the removal of these items could make it difficult for utilities to obtain permissions needed to maintain clearances between inspection cycles which are prudent for reliability and safety due to intervener or landowners exercising their rights and then pointing to this new standard as a the basis for smaller clearances. . Requirement 3 in this draft needs to include a documented plan and to clearly identify the specifics to be included in the plan and provide clarity of expectations. The SDT may not support such specifics as not being consistent with results-based standards development but NERC staff believes otherwise.

Response: The SDT thanks you for your comments. The existing series of items in Requirement R3 along with R3.2 are collectively with the balance of the standard equivalent to the term TVMP. These combined items in R3 are the defense in depth approach that require the TO to maintain vegetation so that it does not enter into the MVCD before the next planned vegetation work, thus accomplishing the equivalent of a C1 without a fill-in-the-blank issue.

- Objectives**:** A qualifier in the standard Objective that it should apply to preventing the risk of vegetation related outages *that could lead to cascading outages.*

  NERC Comment – This qualifier limits the purpose of the standard, which should be to prevent vegetation related outages, not cascading outages. The more outages there are, the less the overall system reliability. An outage does not necessarily have to lead to a cascading outage to be significant and represent a reasonable risk to the BES. References to cascading outages should be removed.

Response: The SDT thanks you for your comments. The SDT has thoughtfully considered every aspect of this version of the Standard to ensure that the pieces are consistent, aligned, and support each other. The SDT added the phrase “with Cascading” not to limit the Standard, but rather to recognize that the 200 kV bright-line for applicability (which is not in question) is founded on the very notion that the 200 kV serves as a proxy for "The Big Three": Cascading, Separation, and Instability. The SDT considered adding all of these conditions to the Purpose statement. However, given the focus of this Standard is on vegetation, and vegetation was deemed to be related to Cascading (i.e. 2003 Blackout report), rather than the other two undesirable system conditions, it seemed more logical and consistent to include the likely outcome of an unmanaged vegetation condition on a Transmission Owner's system. If NERC Staff has evidence that other two are likely related to vegetation, it has not yet been provided to the SDT.

Unlike other types of outages on lines (such as those caused by failed insulators, broken cross-arms, rotten poles and lightning flashover), vegetation outages uniquely affect lines when they are heavily loaded and thus susceptible to a cascading event.

- Background**:** This section excludes vegetations fall-ins and blow-ins from outside the ROW on the basis that they are not preventable.

  NERC Comment – Many fall-ins and blow-ins from outside the ROW are preventable. Trees outside the ROW must be managed adequately to prevent outages on the BES. The work to remove and/or prune trees outside the ROW may be more difficult and costly than such work inside the ROW, but that is not sufficient reason to exclude this work. In addition, utilities wishing to perform such work might be prevented from doing so by regulatory bodies based upon the lack of a specific requirement in this standard.

Response: The SDT thanks you for your comments and has reworded the Background by removing the term non-preventable.

- Requirement 1 & 2: These requirements discuss preventing encroachments into the MVCD of an applicable line that is operating within its Rating.

  NERC Comments –NERC staff would like confirmation that “Rating” is intended to include all published ratings issued by the facility owner, such as Normal, Emergency, etc.

Response: The SDT thanks you for your response. The glossary term "Rating" is adequate to address the issues you raise.

- Requirement 4: R4 states that "Each Transmission Owner, without any intentional time delay, shall notify…"

  NERC Comments: The previous version of the standard included a time limit of 15 minutes once communications became available. This should be reinstated.

Response: The SDT thanks you for your response. The SDT is not aware any posting with a 15 minute rule included.

- Requirement 7: R7 sets the requirement for each Transmission Owner to complete 100 percent of its annual vegetation work plan.

  NERC Comments – NERC is concerned that the draft doesn't have a requirement for a Transmission Owner to have a documented annual plan making Requirement 7 unenforceable. In addition, Requirement 7 has a number of other qualifiers that would seem to allow manipulation of the annual plan to ensure compliance.

Response: The SDT thanks you for your comments. The SDT asserts that a fundamental precept of results-based standards is that having a requirement to complete any particularly activity also presupposes that the elements required to complete the activity are included in the requirement, even if unstated.

- Draft 5 document quality

  NERC Comments – this draft has some typographical errors which need to be fixed. For example, on page 28, reference to use of Table 5 versus Table 7 based on knowledge of maximum transient over-voltage factor is reversed. These edits could probably be handled through a recirculation ballet.

Response: The SDT thanks you for your comments. We agree with the typo you found and we have changed the language in the draft standard.

- Previously raised NERC issues

  NERC Comments – NERC staff posted several comments on the Draft 4 version of this standard in July 2010. NERC believes most of the concerns it raised in those comments are not addressed in Draft 5 and continue to be a concern for NERC.

Response: The SDT thanks you for your comments; however there are not enough specifics for the SDT to respond.

- General compliance and audit issues

  NERC Comments –

  - The whole "sustained outage" concept in R1 (for fall ins and blow ins) is unworkable from an enforcement perspective.
  - The difference between a violation and a non-violation in Draft 5 is whether the registered entity was fortunate with regard to an encroachment. This part should be rewritten to say that any tree contact is a violation. VRFs and VSLs could then be used to address whether the violation was minor or serious.
  - There could be a lot of litigation over whether "circumstances" were really "beyond the control" of the TO. NERC had previously objected to the implementation of a force majeure clause in the standard. If an entity failed to carry out its annual plan, that should be treated as a violation, and any excuses for failing to do so or for changing the plan mid-year all go to whether the penalty should be $0 or substantial.
  - For the evidence retention period, the entity really should retain evidence of compliance until the next compliance audit. Since some TOs may be on a 6 year audit schedule, the 3 year retention period is not sufficient.

Response: The SDT thanks you for your comments.

- The SDT does not understand your comment. The violations under the existing standards are largely due to sustained outages.
- Version 2 has a violation for every known and confirmed encroachment. The Penalty for those encroachments that do no cause Faults is up to $30,000 per violation per day
- The SDT thanks you for your comments. The SDT believes this language is appropriate for this standard due to the many factors related to vegetation that are truly outside the TO's control. Unlike the vast majority of other NERC standards, implementation of FAC-003 is not under

the absolute control of the utilities. These influences range from landowner and agency obstacles to weather events, and as such the SDT believes the force majeure provisions should be applicable. The recognition of this provision is also supported by 90% of the industry. An attempt at similar language is contained in version 1 but it is ambiguous and lacks clarity. This language adds clarity and reduces the opportunity for misapplication. Further, TO's must have supporting evidence for claims that situations are "beyond their control".

- The SDT thanks you for your comments, and will use the NERC approved retention times.

End of Report

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Non-binding Poll of VRFs and VSLs for FAC-003-2 (February 18-28, 2011) Consideration of Comments Report

Project 2007-07 Vegetation Management — September 30, 2011

Summary Consideration:

Some entities expressed concern regarding the use of the MVCD. The SDT explained that the MVCD was established as a beginning of a series of "building blocks" for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions, and that R3 requires that a Transmission Owner to consider the MVCD distances, as well as variables of conductor movement and the variables associated with vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this "building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD.

Other entities questioned if the intent of the standard is to "manage vegetation" or to "prevent outages. The STD responded that In Order 693, FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added).

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 404-446-2563 or via email at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
Gregory S Miller	Baltimore Gas & Electric Company	1	Affirmative	VRFs and VSLs seem reasonable.
Response: The SDT thanks you for your comments.				
Joseph S. Stonecipher	Beaches Energy Services	1	Negative	(See comments for 2007-07.)
Response: The SDT responded in the Successive Ballot Consideration of Comments document.				
Donald S. Watkins	Bonneville Power Administration	1	Affirmative	In R1 and R2 and their associated VSLs, the SDT added the phrase "in order of increasing severity" and added the sentence, "The types of encroachments are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO's vegetation maintenance program." to the Rationale boxes for R1/R2. Do you agree? If answer is no, please explain. BPA prefers the stratified levels of violation severity presented in the table for R1 and R2. Foot note # 2 on page 8 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. Foot note # 4 on page 12 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. In response to comments received that requirement R3 is unclear with respect to intent, the SDT added "maintenance strategies." Do you agree this clarifies the intent? If answer is no, please offer alternative language.

Voter	Entity	Segment	Vote	Comment
				The TO procedures / policies and specifications shall demonstrate the TO's ability to manage the system at all rated conditions to maintain reliability. BPA believes that the intent is clear, but the fundamental approach of using the MVCD (table 2) to manage a vegetation program is still problematic. These values are flashover distances and are way too close. This is acknowledged in a footnote to table 2 but no identification of allowable buffers/distances between energized phase conductors at rated temperatures and vegetation is discussed (this is left up the transmission owners). Clarity is needed on this topic. Setting a finite distance limit based on recognized standards, good science and risk avoidance should be done for the industry. BPA has previously made this comment during the drafting of the standard. It was not addressed then, nor has it been addressed now.
Response: The SDT thanks you for your comments. The footnotes were changed to conform with your suggestions. With respect to comments about the MVCD, R3 does not suggest the MVCD be used as a distance to manage vegetation. The MVCD was established as a beginning of a series of "building blocks" for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions. R3 requires that a Transmission Owner consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this "building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD. In a performance based standard, requirements are focused on "what" needs to be accomplished to achieve desired results and avoids prescriptive requirements of "how" to achieve that result. TO's are in the best position to determine the appropriate management approach suited for their system, rather than a "one size fits all" or "fill in the blank" requirement that could suppress best practices for vegetation management.				
Randall McCamish	City of Vero Beach	1	Negative	Vero Beach's concern is that entities may not be able prove compliance with the standard. R1 and R2 say that: "Each

Voter	Entity	Segment	Vote	Comment
				Transmission Owner shall manage vegetation to prevent encroachments ...". If the requirements were interpreted such that "manage" is the operative word, then, we are OK because we can provide evidence of managing a program, such as a vegetation management plan and evidence of executing that plan (which does not align with the Measures). However, that 1) would cause the standard to not be performance based, and 2) it would be duplicative of the other requirements of the standard. If the requirements were interpreted with "prevent encroachment" as the operative phrase (which would be an incorrect interpretation from the construct of the sentence) there is no way to provide sufficient evidence that encroachment was prevented during the audit-period. The suggested Measures are not sufficient evidence to prove compliance with that interpretation of the requirement. For instance, most encroachments do not result in outages; hence, lack of outages cannot prove that there were no encroachments, and real time observations are insufficient because it is a spot-check that does not cover the audit period. There are other weaknesses in the standard, such as R4 being un-measurable therefore unenforceable. However, in the guilty until proven innocent paradigm we live in, FMPA's primary concern is that industry could be put into a no-win situation of not being able to prove compliance with the standard if R1 and R2 are interpreted as "prevent encroachment", and if R1 and R2 are interpreted as "manage" then it is not a performance based standard as advertised. Vero Beach suggests one of two approaches: 1. Performance based focused on preventing vegetation

Voter	Entity	Segment	Vote	Comment
				related outages. For instance: "Each Transmission Owner shall prevent vegetation related outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. 2. Modify the standard to be similar to the currently mandatory non-results based standard and focus on the word "manage". This would essentially mean eliminating R1 and R2 since the rest of the standard focuses on having a plan and managing to that plan..
Response: The SDT thanks you for your comments. In Order 693, FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.				
Christopher L de Graffenried	Consolidated Edison Co. of New York	1	Affirmative	The VSLs in R6 and R7 should be consistent with each other: R6 says '...TO failed to inspect 5% or less.....' and R7 says '...TO failed to complete up to 5%....' They both should use the same verbiage in each VSL whether it is 'x% or less' or 'up to and including x%.'
Response: The SDT thanks you for your comments. The SDT has changed the verbiage in the VSLs in R6 and R7 such that it addresses you suggestion.				
Michael Gammon	Kansas City Power & Light Co.	1	Negative	The VSL for Requirement 7 should be clear and specifically state this specifically addresses only "all applicable lines".
Response: The SDT thanks you for your comments. The team has added the phrase, "applicable lines" as proposed to all the VSLs for R7.				
Stan T.	Keys Energy	1	Negative	Concern is that entities may not be able prove compliance with the standard. R1 and R2 say that: "Each Transmission

Voter	Entity	Segment	Vote	Comment
Rzad	Services			Owner shall manage vegetation to prevent encroachments ...". If the requirements were interpreted such that "manage" is the operative word, then, we are OK because we can provide evidence of managing a program, such as a vegetation management plan and evidence of executing that plan (which does not align with the Measures). However, that 1) would cause the standard to not be performance based, and 2) it would be duplicative of the other requirements of the standard. If the requirements were interpreted with "prevent encroachment" as the operative phrase (which would be an incorrect interpretation from the construct of the sentence) there is no way to provide sufficient evidence that encroachment was prevented during the audit-period. The suggested Measures are not sufficient evidence to prove compliance with that interpretation of the requirement. For instance, most encroachments do not result in outages; hence, lack of outages cannot prove that there were no encroachments, and real time observations are insufficient because it is a spot-check that does not cover the audit period. There are other weaknesses in the standard, such as R4 being un-measurable therefore unenforceable. However, in the guilty until proven innocent paradigm we live in, FMPA's primary concern is that industry could be put into a no-win situation of not being able to prove compliance with the standard if R1 and R2 are interpreted as "prevent encroachment", and if R1 and R2 are interpreted as "manage" then it is not a performance based standard as advertised. one of two approaches are suggested: Performance based focused on preventing vegetation related outages. For instance: "Each Transmission Owner shall prevent vegetation related

Voter	Entity	Segment	Vote	Comment
				outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. Modify the standard to be similar to the currently mandatory non-results based standard and focus on the word "manage". This would essentially mean eliminating R1 and R2 since the rest of the standard focuses on having a plan and managing to that plan..
Response: The SDT thanks you for your comments. In Order 693 FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.				
Walt Gill	Lake Worth Utilities	1	Negative	concern is that entities may not be able prove compliance with the standard. R1 and R2 say that: "Each Transmission Owner shall manage vegetation to prevent encroachments ...". If the requirements were interpreted such that "manage" is the operative word, then, we are OK because we can provide evidence of managing a program, such as a vegetation management plan and evidence of executing that plan (which does not align with the Measures). However, that 1) would cause the standard to not be performance based, and 2) it would be duplicative of the other requirements of the standard. If the requirements were interpreted with "prevent encroachment" as the operative phrase (which would be an incorrect interpretation from the construct of the sentence) there is no way to provide sufficient evidence that encroachment was prevented during the audit-period. The suggested Measures are not sufficient evidence to prove compliance

Voter	Entity	Segment	Vote	Comment
				with that interpretation of the requirement. For instance, most encroachments do not result in outages; hence, lack of outages cannot prove that there were no encroachments, and real time observations are insufficient because it is a spot-check that does not cover the audit period. There are other weaknesses in the standard, such as R4 being un-measurable therefore unenforceable. However, in the guilty until proven innocent paradigm we live in, FMPA's primary concern is that industry could be put into a no-win situation of not being able to prove compliance with the standard if R1 and R2 are interpreted as "prevent encroachment", and if R1 and R2 are interpreted as "manage" then it is not a performance based standard as advertised. suggest one of two approaches: 1. Performance based focused on preventing vegetation related outages. For instance: "Each Transmission Owner shall prevent vegetation related outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. 2. Modify the standard to be similar to the currently mandatory non-results based standard and focus on the word "manage". This would essentially mean eliminating R1 and R2 since the rest of the standard focuses on having a plan and managing to that plan..
Response: The SDT thanks you for your comments. In Order 693 FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.				

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td>Marvin E VanBebber</td><td>Oklahoma Gas and Electric Co.</td><td>1</td><td>Negative</td><td>R3 VSL leaves a lot open to interpetation in the analysis area. This is one where the auditor could be heavy handed if he desired.</td></tr>
<tr><td colspan="5">Response: The SDT thanks you for your comments. The Requirement 3 VSL does in fact give TO significant latitude with respect to maintaining appropriate clearances. As noted in the Rationale, “The documentation provides a basis for evaluating the competency of the Transmission Owner’s vegetation program. There may be many acceptable approaches to maintain clearances.” In a performance based standard, requirements (and associated VSLs) are focused on “what” needs to be accomplished to achieve desired results and avoids prescriptive requirements of “how” to achieve that result. TO’s are in the best position to determine the appropriate management approach suited for their system rather than a “one-size-fits-all” requirement that could suppress best practices for vegetation management. With this in mind, if the TO is audited, and it has a well crafted vegetation management program and has properly documented procedures and results, it should be in a good position.</td></tr>
<tr><td>Keith V Carman</td><td>Tri-State G & T Association, Inc.</td><td>1</td><td>Affirmative</td><td>There needs to be a change in the footnote 2 and footnote 4 to remove the exemption for “arboricultural activities or horticultural or agricultural activities” and replace it with the term “ installation of”.</td></tr>
<tr><td colspan="5">Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.</td></tr>
<tr><td>Mark B Thompson</td><td>Alberta Electric System Operator</td><td>2</td><td>Abstain</td><td>VRFs and VSLs are set by Provincial authorities in Alberta.</td></tr>
<tr><td colspan="5">Response: The SDT thanks you for your comments.</td></tr>
<tr><td>David A. Lapinski</td><td>Consumers Energy</td><td>3</td><td>Negative</td><td>Comments on FAC-003-2 February 25, 2011 Consumers Energy submits the following comments on FAC-003-2: In general we are please with FAC-003-2 and the many clarifications that the STD has made in this version of the standard. However, we do have one major disagreement with the STD and cannot support this standard as drafted.</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
				We disagree with the use of the Minimum Vegetation Clearance Distance (MVCD) developed by the drafting team for Requirements R1 and R2. These distances are not the design distances used for designing and constructing transmission facilities as stated in the document for minimum distances between conductors and grounded objects. The proposed Table 2 provides a distance of 3.12 feet as the acceptable distance for an alternate current 345kV line at sea level. This distance is considerably less than the distance used for line design to separate the grounded tower structure from the energized conductor. If the distance in Table 2 is acceptable to prevent energized portions of a transmission line from grounding to a tree why then is this distance not the design criteria used for tower design to prevent flashover from conductor to tower? The STD needs to explain why a ground tree should have a different standard that a grounded steel tower or wood pole structure. The STD erroneously viewed the possibility of transient over voltage as only occurring during re-energizing and not from natural events such as a lightning strike that can occur and does occur to energized operating lines. Secondly, the proposed distances in Table 2 are considerably less than the distances specified in OSHA requirements for air gap clearance required by tree workers to safely remove trees or limbs from conductors energized at the voltages specified. A transmission owner/operator could let a tree grow to within 3.5 feet of a 345 kV line and not be in violation of this proposed standard. To remove the tree, the line would have to be de-energized, tagged, tested de-energized, and grounded. Working clearance would have to be established by the operating entity and then the tree crew could remove the

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				tree. The net result is the loss of the capacity of the line because an outage was forced on the line in order to remove the tree that did not trigger a violation of FAC-003-2. This situation, in our opinion, is a violation of the intent of the standard, which is to ensure the continued operation of the line. Therefore, the minimum distance any tree should be able to approach a conductor is more than the minimum requirement for air gap distance between the tree and conductor as required by OSHA worker standards. The STD did not like referring to another standard to provide the distance requirements for R1 and R2. This can be alleviated by putting in a table with the IEEE 516 distances but not reference it as the IEEE 516 standard. The distances provided in the current draft do not adequately provide or ensure the continued safe operation of the transmission facilities in the United States and the reasoning for the distances provided is unfounded and not based on current design practices.

Response: The SDT thanks you for your comments. You are correct that these distances do not represent complete design specifications for towers, nor define and describe safe worker approach distances. These practices are correctly specified in the other standards you referenced. The SDT feels the standard is clear in that regard.   The footnote associated with the Table 2 distances clearly states that these are only distances to prevent flashover under appropriate conditions. The SDT would also like to point out that the transient overvoltage factors used to derive these distances are the maximums normally seen with a transmission line in steady state service. Thus, a tower design would have to account for the larger overvoltage factors that are possible while taking lines out of service.

As has been stated before, these distances were derived using a known set of line design equations and only represent distances that will prevent spark-over from the transmission line to a grounded object. These are not distances to be managed to – they have been established as a beginning of a series of "building blocks" for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions.

R3 requires that a Transmission Owner' consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner's overall vegetation management approach.   The net result of this

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"building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD. These distances are smaller than safety standard distances that have many other factors involved in the determination, such as inadvertent human movement and larger safety factors. In regard to the over-voltages caused by lightning, even the maximum overvoltage factors contained in the IEEE-516 tables do not account for these.				
Russell A Noble	Cowlitz County PUD	3	Negative	Referring back to Cowlitz' negative vote made on the 7/9-19/2010 ballot, Cowlitz tried to convey the problem that the statement in R4 "without intentional time delay" will require subjective judgment on the part of the auditor. In other words, maintaining equal auditing standard throughout the interconnection will be impossible with this verbiage in a requirement. Cowlitz agrees with the SDT that establishing an equitable time frame is very difficult (it may be impossible!); however leaving it to the judgment of the auditor to determine whether an intentional delay was made is most disagreeable. Cowlitz respectfully points out that the SDT did not adequately address the subjective nature the auditor is forced into with this requirement. If establishing "[t]he time required by the to report an issue is subject to many variables..." and "[f]or this reason it is difficult to establish a time period which would fairly apply to all TO's," how does leaving this to the auditor to decide going to make it any better?
Response: The SDT thanks you for your comments. The SDT believes that it was not prudent to suggest a quantitative time element for notification in R4. The technical reference offers examples of acceptable unintentional delays for your review. The SDT notes that this language is already embodied in at least one other FERC-approved, in-force Standard.				
Charles Locke	Kansas City Power & Light Co.	3	Negative	The VSL for Requirement 7 should be clear and specifically state this specifically addresses only "all applicable lines".

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Response: The SDT thanks you for your comments. The team has added the phrase, "applicable lines" as proposed to all the VSLs for R7.				
Mace Hunter	Lakeland Electric	3	Affirmative	R1. Each Transmission Owner shall manage vegetation to prevent encroachments of the types shown below, ---------------- and all Rated Electrical Operating Conditions.2 1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage, that is not corrected within 5 working days of discovery, Make the same change to R2 Type 1 encroachment and reflect the changes in Table 1. Rational: This condition would enable a entity to discover an encroachment and clear it without having to self report a possible violation as long as the conditions was corrected within 5 working days. The change should encourage extra inspections for problem areas more often than annually as required in R6. There should be no negative consequences for diligent inspection of lines as long as the problem is clear with a defined time such as 5 or 10 working days.
Response: The SDT thanks you for your comment. As a general rule, a revised standards should not be less stringent than the existing standard it replaces. In the existing standard, a violation occurs when the encroachment occurs. A 'find and fix' of five days would be viewed as a lowering the level of performance required by the current standard.				
Rick Syring	Cowlitz County PUD	4	Negative	Referring back to Cowlitz' negative vote made on the 7/9-19/2010 ballot, Cowlitz tried to convey the problem that the statement in R4 "without intentional time delay" will require subjective judgment on the part of the auditor. In other words, maintaining equal auditing standard throughout the interconnection will be impossible with this verbiage in a requirement. Cowlitz agrees with the SDT that establishing an equitable time frame is very difficult (it may be impossible!); however leaving it to the judgment of the

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				auditor to determine whether an intentional delay was made is most disagreeable. Cowlitz respectfully points out that the SDT did not adequately address the subjective nature the auditor is forced into with this requirement. If “[t]he time required by the entity to report an issue is subject to many variables...” and “[f]or this reason it is difficult to establish a time period which would fairly apply to all TO’s,” how does leaving this to the auditor to decide going to make it any better? You will be forcing the audited entity to "prove the negative."
Response: The SDT thanks you for your comments. The SDT believes that it was not prudent to suggest a quantitative time element for notification in R4. The technical reference offers examples of acceptable unintentional delays for your review. The SDT notes that this language is already embodied in at least one other FERC-approved, in-force Standard.				
Frank Gaffney	Florida Municipal Power Agency	4	Negative	R1 and R2 requirement reads: "Each Transmission Owner shall manage to prevent encroachment ....". The results of manage would be invoices of tree trimming actually performed, documentation of a vegetation management program that would be managed to, etc. However, the Measures proposed are all actual outages which are neither evidence of management nor evidence of encroachment since there can be encroachment without an outage, and in fact, many if not most encroachments do not result in outages. Hence, the Measures are inconsistent with the requirements. Further, there is ambiguity of the action required in requirements R1 and R2 - e.g., do entities need evidence that they: 1) "manage", or 2) "prevent encroachment"; or 3) as implied by the Measures, prevent vegetation related outages?. In other words, what needs to be proven through evidence? Certainly the third, prevent vegetation related outages, is not in the Requirement; yet, that us what is proposed for the Measures, highlighting the

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				inconsistency between Requirements and Measures. But, how would the ambiguity between "manage" and "prevent encroachment" be resolved? One auditor could interpret that the requirement is to "manage" and accept a vegetation management program and plan and proof that the plan was executed as appropriate evidence. Another auditor could interpret that "prevent" is the key word and look for evidence proving that there was never a vegetation encroachment. How would evidence be produced to provide the auditor that vegetation never encroached? Would video cameras and other surveillance measures need to operate 24 hours a day? Would we cause an entity to survey the lines periodically? One can easily see that "prevent encroachment" is inappropriate here since it is infeasible to create evidence of compliance. FMPA suggests one of two approaches: Eliminate the word manage, but do not focus on encroachment and instead focus on outages. For instance: "Each Transmission Owner shall prevent vegetation related outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. Focus on the word "manage", similar to the existing FAC-003 standard, and move R3 to a new R1 to develop a management plan, and then the existing R1 and R2 become R2 an R3 and require execution of that plan in the words of R7, which would in turn enables elimination of R7.
Response: The SDT thanks you for your comments. In Order 693 FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation"** (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct				

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inspections in which clearances are evaluated.				
Douglas Hohlbaugh	Ohio Edison Company	4	Affirmative	For the Requirement R1 and R2 VSLs, we suggest that the proposed Moderate (fall-ins) and High (blowing together) VSL be interchanged. We believe that fall-ins are more severe encroachments than blowing together and the categories listed in the compliance section support this point. Category 1 (grow-ins) is most severe, followed by Category 2 & 3 (fall-ins) and Category 4 (blowing together. If the team elects to not make the suggested VSL changes then a change in the category listing within the compliance section is warranted. Either way they should be consistent.
Response: The SDT believes that there is consensus that "blowing-together" events are more indicative of a program failure than are "fall-in" events. Further, the risk to the transmission system from blowing-together events is greater than for fall-ins; partly because blowing-together events are more likely to repeat themselves, whereas fall-ins generally end on the spot. The SDT agrees with you that the ordering of the categories seems to convey a different message; however, re-sequencing the categories in order of severity would have led to a clash with the existing categories in Version 1 and thus would have provoked widespread confusion.				
Francis J. Halpin	Bonneville Power Administration	5	Affirmative	In R1 and R2 and their associated VSLs, the SDT added the phrase "in order of increasing severity" and added the sentence, "The types of encroachments are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO's vegetation maintenance program." to the Rationale boxes for R1/R2. Do you agree? If answer is no, please explain. BPA prefers the stratified levels of violation severity presented in the table for R1 and R2. Foot note # 2 on page 8 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities.

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				Foot note # 4 on page 12 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. In response to comments received that requirement R3 is unclear with respect to intent, the SDT added “maintenance strategies.” Do you agree this clarifies the intent? If answer is no, please offer alternative language. The TO procedures / policies and specifications shall demonstrate the TO’s ability to manage the system at all rated conditions to maintain reliability. BPA believes that the intent is clear, but the fundamental approach of using the MVCD (table 2) to manage a vegetation program is still problematic. These values are flashover distances and are way too close. This is acknowledged in a footnote to table 2 but no identification of allowable buffers/distances between energized phase conductors at rated temperatures and vegetation is discussed (this is left up the transmission owners). Clarity is needed on this topic. Setting a finite distance limit based on recognized standards, good science and risk avoidance should be done for the industry. BPA has previously made this comment during the drafting of the standard. It was not addressed then, nor has it been addressed now.
Response: The SDT thanks you for your comments. The footnotes were changed to conform with your suggestions. With respect to comments about the MVCD, R3 does not suggest the MVCD be used as a distance to manage vegetation. The MVCD was established as a beginning of a series of “building blocks” for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions. R3 requires that a Transmission Owner consider the MVCD distances, as well as variables of conductor movement and				

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vegetation growth, when designing the Transmission Owner’s overall vegetation management approach. The net result of this “building block” approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD distances. In a performance based standard, requirements are focused on “what” needs to be accomplished to achieve desired results and avoids prescriptive requirements of “how” to achieve that result. TO’s are in the best position to determine the appropriate management approach suited for their system rather than a “one size fits all” requirements that could suppress best practices for vegetation management.				
James B Lewis	Consumers Energy	5	Negative	See comments on the Standard.
Response: The SDT thanks you for your comments that were made during the formal comment period for the Standard; the SDT’s responses to those comments are available there.				
Bob Essex	Cowlitz County PUD	5	Negative	Referring back to Cowlitz’ negative vote made on the 7/9-19/2010 ballot, Cowlitz tried to convey the problem that the statement in R4 “without intentional time delay” will require subjective judgment on the part of the auditor. In other words, maintaining equal auditing standard throughout the interconnection will be impossible with this verbiage in a requirement. Cowlitz agrees with the SDT that establishing an equitable time frame is very difficult (it may be impossible!); however leaving it to the judgment of the auditor to determine whether an intentional delay was made is most disagreeable. Cowlitz respectfully points out that the SDT did not adequately address the subjective nature the auditor is forced into with this requirement. If establishing “[t]he time required by the to report an issue is subject to many variables...” and “[f]or this reason it is difficult to establish a time period which would fairly apply to all TO’s,” how does leaving this to the auditor to decide going to make it any better?

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Response: The SDT thanks you for your comments. The SDT believes that it was not prudent to suggest a quantitative time element for notification in R4. The technical reference offers examples of acceptable unintentional delays for your review. The SDT notes that this language is already embodied in at least one other FERC-approved, in-force Standard.				
David Schumann	Florida Municipal Power Agency	5	Negative	R1 and R2 requirement reads: "Each Transmission Owner shall manage to prevent encroachment ....". The results of manage would be invoices of tree trimming actually performed, documentation of a vegetation management program that would be managed to, etc. However, the Measures proposed are all actual outages which are neither evidence of management nor evidence of encroachment since there can be encroachment without an outage, and in fact, many if not most encroachments do not result in outages. Hence, the Measures are inconsistent with the requirements. Further, there is ambiguity of the action required in requirements R1 and R2 - e.g., do entities need evidence that they: 1) "manage", or 2) "prevent encroachment"; or 3) as implied by the Measures, prevent vegetation related outages?. In other words, what needs to be proven through evidence? Certainly the third, prevent vegetation related outages, is not in the Requirement; yet, that us what is proposed for the Measures, highlighting the inconsistency between Requirements and Measures. But, how would the ambiguity between "manage" and "prevent encroachment" be resolved? One auditor could interpret that the requirement is to "manage" and accept a vegetation management program and plan and proof that the plan was executed as appropriate evidence. Another auditor could interpret that "prevent" is the key word and look for evidence proving that there was never a vegetation encroachment. How would evidence be produced to provide the auditor that vegetation never encroached?

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				Would video cameras and other surveillance measures need to operate 24 hours a day? Would we cause an entity to survey the lines periodically? One can easily see that "prevent encroachment" is inappropriate here since it is infeasible to create evidence of compliance. FMPA suggests one of two approaches: Eliminate the word manage, but do not focus on encroachment and instead focus on outages. For instance: "Each Transmission Owner shall prevent vegetation related outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. Focus on the word "manage", similar to the existing FAC-003 standard, and move R3 to a new R1 to develop a management plan, and then the existing R1 and R2 become R2 an R3 and require execution of that plan in the words of R7, which would in turn enables elimination of R7.
Response: The SDT thanks you for your comments. In Order 693 FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.				
Brenda S. Anderson	Bonneville Power Administration	6	Affirmative	BPA Comments with Yes Vote: In R1 and R2 and their associated VSLs, the SDT added the phrase "in order of increasing severity" and added the sentence, "The types of encroachments are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO's vegetation maintenance program." to the Rationale boxes for R1/R2. Do you agree? If answer is no, please explain. BPA prefers the stratified levels of violation severity

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				presented in the table for R1 and R2. Foot note # 2 on page 8 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. Foot note # 4 on page 12 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. In response to comments received that requirement R3 is unclear with respect to intent, the SDT added “maintenance strategies.” Do you agree this clarifies the intent? If answer is no, please offer alternative language. The TO procedures / policies and specifications shall demonstrate the TO’s ability to manage the system at all rated conditions to maintain reliability. BPA believes that the intent is clear, but the fundamental approach of using the MVCD (table 2) to manage a vegetation program is still problematic. These values are flashover distances and are way too close. This is acknowledged in a footnote to table 2 but no identification of allowable buffers/distances between energized phase conductors at rated temperatures and vegetation is discussed (this is left up the transmission owners). Clarity is needed on this topic. Setting a finite distance limit based on recognized standards, good science and risk avoidance should be done for the industry. BPA has previously made this comment during the drafting of the standard. It was not addressed then, nor has it been addressed now.
Response: The SDT thanks you for your comments. The footnotes were changed to conform with your suggestions. With respect to comments about the MVCD, R3 does not suggest the MVCD be used as a distance to manage vegetation. The MVCD				

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was established as a beginning of a series of "building blocks" for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions. R3 requires that a Transmission Owner' consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this "building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD distances. In a performance based standard, requirements are focused on "what" needs to be accomplished to achieve desired results and avoids prescriptive requirements of "how" to achieve that result. TO's are in the best position to determine the appropriate management approach suited for their system rather than a "one size fits all" requirement that could suppress best practices for vegetation management.				
Nickesha P Carrol	Consolidated Edison Co. of New York	6	Affirmative	The VSLs in R6 and R7 should be consistent with each other: R6 says '...TO failed to inspect 5% or less.....' and R7 says '...TO failed to complete up to 5%....' They both should use the same verbiage in each VSL whether it is 'x% or less' or 'up to and including x%.'
Response: The SDT thanks you for your comments. The SDT has changed the verbiage in the VSLs in R6 and R7 such that it addresses you suggestion.				
Mark S Travaglianti	FirstEnergy Solutions	6	Affirmative	FirstEnergy supports standard FAC-003-2 and would appreciate consideration of our comments submitted through the formal comment period.
Response: The SDT thanks you for your comments and has reviewed and responded to your comments made during the formal comment period.				
Thomas E Washburn	Florida Municipal Power Pool	6	Negative	The concern is that entities may not be able prove compliance with the standard. R1 and R2 say that: "Each Transmission Owner shall manage vegetation to prevent encroachments ...". If the requirements were interpreted such that "manage" is the operative word, then, we are OK because we can provide evidence of managing a program, such as a vegetation management plan and evidence of

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				executing that plan (which does not align with the Measures). However, that 1) would cause the standard to not be performance based, and 2) it would be duplicative of the other requirements of the standard. If the requirements were interpreted with "prevent encroachment" as the operative phrase (which would be an incorrect interpretation from the construct of the sentence) there is no way to provide sufficient evidence that encroachment was prevented during the audit-period. The suggested Measures are not sufficient evidence to prove compliance with that interpretation of the requirement. For instance, most encroachments do not result in outages; hence, lack of outages cannot prove that there were no encroachments, and real time observations are insufficient because it is a spot-check that does not cover the audit period. There are other weaknesses in the standard, such as R4 being un-measurable therefore unenforceable. However, in the guilty until proven innocent paradigm we live in, FMPA's primary concern is that industry could be put into a no-win situation of not being able to prove compliance with the standard if R1 and R2 are interpreted as "prevent encroachment", and if R1 and R2 are interpreted as "manage" then it is not a performance based standard as advertised. Performance based focused on preventing vegetation related outages. For instance: "Each Transmission Owner shall prevent vegetation related outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. Modify the standard to be similar to the currently mandatory non-results based standard and focus on the word "manage". This would essentially mean eliminating R1

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				and R2 since the rest of the standard focuses on having a plan and managing to that plan..
Response: The SDT thanks you for your comments. In Order 693 FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.				
Thomas Saitta	Kansas City Power & Light Co.	6	Negative	The VSL for Requirement 7 should be clear and specifically state this specifically addresses only "all applicable lines".
Response: The SDT thanks you for your comments. The team has added the phrase, "applicable lines" as proposed to all the VSLs for R7.				
James Eckelkamp	Progress Energy	6	Affirmative	There needs to be a change in the footnote 2 and footnote 4 to remove the exemption for "arboricultural activities or horticultural or agricultural activities" and replace it with the term "installation of."
Response: The SDT thanks you for your comments. The changes to the footnotes have been made as proposed.				
Guy V. Zito	Northeast Power Coordinating Council, Inc.	10	Affirmative	The use of the term "encroachment", and the lack of clarity in defining clearances is an issue that should be addressed by the Drafting Team.
Response: The SDT thanks you for your comments. With regard to the use of "encroachment" and the clarity in defining clearances as it relates to the VRFs and VSLs, the SDT has taken what was a "gray" area in Version 1 and added more clarity with regard to compliance. In Version 1, it is not actually clear whether experiencing an encroachment or experiencing outage is a violation of the standard. The SDT recognized this concern and has addressed this via the proposed VSLs for R1 and R2. These proposed VSLs are designed such to correlate to the severity level of failure of the Transmission Owner's vegetation management program.				

Voter	Entity	Segment	Vote	Comment
If you refer to the VSLs for R1 and R2, only the "Lower" VSLs apply to an encroachment, and that has been defined as "an encroachment into the MVCD observed in Real-time, absent a Sustained Outage." The "MVCD" clearance distance is clearly defined in Table 2 of the Standard. After the Lower VSL level for these requirements, the Moderate to Severe VSLs are correlated more directly to the severity of failure of the Transmission Owner's vegetation management program associated with a Sustained Outage. The SDT makes this recommendation of VSLs based on this being an improvement for compliance clarity over version 1 of the standard.				
Anthony E Jablonski	ReliabilityFirst Corporation	10	Negative	ReliabilityFirst votes negative and has the following comments regarding the VRFs and VSLs: 1. VRF for R1 and R2 a. The Final Report on the August 14th, 2003 Blackout in the United States and Canada: Causes and Recommendations Blackout Report, highlights the importance of all vegetation management work by identifying inadequate vegetation management as one of the causes of the 2003 Blackout. Based on the Blackout Report there should be no distinction between encroachments of applicable line(s) identified as an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path(s) and encroachments of applicable line(s) not identified as an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path(s). Therefore, ReliabilityFirst recommends that VRFs should be the same for R1 and R2. 2. VSL for R3 a. Since this requirement has sub-parts associated with it, the associated sub-part number should be referenced in the VSL itself.

Voter	Entity	Segment	Vote	Comment
				3. VSL for R4 a. The words in the VLS do not match the language in the requirement. The words "vegetation threat" is not mentioned in Requirement R4. Based on the FERC Guideline #3 "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement" 4. VSL for R6 a. The following qualifier should be added to the end of each of the four VSLs, "...at least once per calendar year and with no more than 18 months between inspections on the same ROW" to be consistent with the corresponding requirement and in accordance with the FERC Guideline #3. 5. VSL for R7 a. There is no associated VSL dealing with the second part of the requirement which references that "... the Modifications to the work plan... must be documented." Where does an entity fall if they have complete 100% of its annual vegetation work plan, but failed to document any modifications to the work plan? This aspect of the requirement should be addressed in the corresponding VSLs.

Response: The SDT thanks you for your comments.

1) In Order 693 FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). Following that concept, the SDT used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. .

R1 and R2 are dealing with the differentiation between lines that fall into an IROL or WECC Transfer Path definition and those lines that do not. The SDT asserts that different VRF's for IROL and non-IROL lines strengthens the reliability of the standard. Vegetation managers that do not know which lines are IROL or WECC Transfer Paths may be inappropriately limiting resources allocated to vegetation management for an IROL line or a WECC Transfer Path. A vegetation manager must ensure that the

Voter	Entity	Segment	Vote	Comment
IROL lines and WECC transfer paths are absolutely clear. By correctly identifying the risk associated with an IROL line and/or a WECC Transfer Path, the standard helps to assure that appropriate resources are applied. 2) The sub-parts referred to are part of the RBS building block approach to document how a TO prevents encroachment of vegetation into the MVCD. The sub parts are not separate elements but make up the processes, strategies, procedures or specifications to prevent encroachment in to the MVCD. 3) The SDT believes the correlation between R4 and the VSL is appropriate. 4) The SDT believes the correlation between R6 and the VSL is appropriate. 5) The wording in the VSL for R7 has been modified to address modifications to the annual work plan.				

Successive Ballot (February 18-28, 2011) Consideration of Comments Report

Project 2007-07 Vegetation Management — September 30, 2011

Summary Consideration:
In order to be consistent with the latest version of NERC's Results Based Standards template, the heading "Objective" was replaced with "Purpose," and the numbering, headings, and sections were reformatted as necessary.

Several entities expressed concern with the use of the Minimum Vegetation Clearance Distance (MVCD) and elimination of Clearance 1. With respect to comments about the MVCD, R3 does not suggest the MVCD be used as a distance to manage vegetation. The MVCD was established as a beginning of a series of "building blocks" for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions. R3 requires that a Transmission Owner consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this "building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD. In a performance-based standard, requirements are focused on "what" needs to be accomplished to achieve desired results and avoids prescriptive requirements of "how" to achieve that result. TO's are in the best position to determine the appropriate management approach suited for their system, rather than a "one size fits all" or "fill in the blank" requirement that could suppress best practices for vegetation management.

Other entities questioned whether the goal of the standard was to "prevent outages" or to "manage vegetation." In Order 693, FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way by maintaining safe clearances between transmission lines and vegetation." The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.

Some entities expressed concern with the mandatory inspection intervals proposed in the standard. The SDT recognizes that a number of Transmission Owners in North America may prefer to set their own inspection intervals. Because there is substantial industry support for an annual inspection interval the SDT believes that the industry is best served with this approach.

Several entities suggested making minor changes to clarify the footnotes. The team did so.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 404-446-2563 or at herb.scrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Paul B. Johnson	American Electric Power	1	Affirmative	American Electric Power believes that the phrase "arboricultural activities or horticultural or agricultural activities" was mistakenly introduced into Footnotes 2 and 4, and should be deleted from both footnotes. If the phrase remains in the Standard, it may empower orchard growers, landowners and others to plant trees on the right of way and challenge Transmission Owners' rights to perform maintenance on the presumption that the standard will exempt the TO from violating the outage or encroachment requirements. For increased clarity, AEP offers the following change to the second paragraph of M1, as well as the second paragraph of M2. The original text "If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation" should be replaced

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
				with "If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation growing into or blowing together with the conductor within the ROW, this shall be considered the equivalent of a Real-time observation. A brief encroachment caused by falling vegetation passing through the MVCD is not considered an encroachment in this requirement".
Response: Thank you for your comments. The SDT made suggested changes to the footnotes as proposed. Regarding the issue of fall-ins, the SDT is sympathetic to your concern. In fact, the SDT had originally crafted language similar to that which you suggested. However, due to concerns expressed by regulators and others, the exemption for encroachment violations due to falling vegetation from inside the right of way was removed.				
Robert D Smith	Arizona Public Service Co.	1	Negative	Overall comment: The objective, as written, is about outages that can lead to cascading and not about reliability. Recommended change to Standard Objective: To maintain a reliable electric transmission system, implement a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW.
Response: The SDT thanks you for your comment. With respect to the Purpose as written in the proposed standard, the language clearly states "To improve the reliability of the electric Transmission system…" The SDT made it a point to keep the Purpose as concise as possible without getting into issues that are covered further in the body of the standard.				
John Bussman	Associated Electric Cooperative, Inc.	1	Negative	R1 - "Each Transmission Owner shall manage vegetation to prevent encroachments of the types shown below, into the Minimum Vegetation Clearance Distance (MVCD) of any of its applicable line(s) identified as an element of an Interconnection Reliability Operating Limit (IROL) in the planning horizon by the Planning Coordinator; or Major Western Electricity Coordinating Council (WECC) transfer

Voter	Entity	Segment	Vote	Comment
				path(s); operating within its Rating and all Rated Electrical Operating Conditions...” The following is my preliminary comment on this requirement. R1 - Associated Electric Cooperative Inc wants to thank the SDT for their hard work and all the effort associated with this standard. However we currently disagrees with the inclusion in this requirement of any and all IROLs identified within the entire planning horizon (typically 10 years or more). Associated Electric certainly agrees that in real time and in the near term sub 200 kV elements of an IROL should be subject to R1. It seems unreasonable, however, to include a sub 200 kV transmission line that might become an IROL element 10 years in the future. Perhaps the time frame could be limited to the Transmission Owner’s planned maintenance cycle.
Response: The SDT thanks you for your comment, and has revised the Standard’s effective dates (exceptions) accordingly.				
Gregory S Miller	Baltimore Gas & Electric Company	1	Affirmative	There seems to be a marginal level of improvement over the previous drafts.
Response: The SDT thanks you for your comment.				
Joseph S. Stonecipher	Beaches Energy Services	1	Negative	R1 and R2 Requirement reads: "Each Transmission Owner shall manage to prevent encroachment ....". The results of manage would be invoices of tree trimming actually performed, documentation of a vegetation management program that would be managed to, etc. However, the Measures proposed are all actual outages which are neither

Voter	Entity	Segment	Vote	Comment
				evidence of management nor evidence of encroachment since there can be encroachment without an outage, and in fact, many if not most encroachments do not result in outages. Hence, the Measures are inconsistent with the Requirements. Further, there is ambiguity of the action required in requirements R1 and R2 - e.g., do entities need evidence that they: 1) "manage", or 2) "prevent encroachment"; or 3) as implied by the Measures, prevent vegetation related outages? In other words, what needs to be proven through evidence? Certainly the third, prevent vegetation related outages, is not in the Requirement; yet, that us what is proposed for the Measures, highlighting the inconsistency between Requirements and Measures. But, how would the ambiguity between "manage" and "prevent encroachment" be resolved? One auditor could interpret that the Requirement is to "manage" and accept a vegetation management program and plan and proof that the plan was executed as appropriate evidence. Another auditor could interpret that "prevent" is the key word and look for evidence proving that there was never a vegetation encroachment. How would evidence be produced to provide the auditor that vegetation never encroached? Would video cameras and other surveillance measures need to operate 24 hours a day? Would we cause an entity to survey the lines periodically? One can easily see that "prevent encroachment" is inappropriate here since it is infeasible to create evidence of compliance.

Response: The SDT thanks you for your comments. In Order 693, FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances**

Voter	Entity	Segment	Vote	Comment
between transmission lines and vegetation" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.				
Donald S. Watkins	Bonneville Power Administration	1	Affirmative	R2. Do you agree? If answer is no, please explain. BPA prefers the stratified levels of violation severity presented in the table for R1 and R2. Foot note # 2 on page 8 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. Foot note # 4 on page 12 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. In response to comments received that requirement R3 is unclear with respect to intent, the SDT added "maintenance strategies." Do you agree this clarifies the intent? If answer is no, please offer alternative language. The TO procedures / policies and specifications shall demonstrate the TO's ability to manage the system at all rated conditions to maintain reliability. BPA believes that the intent is clear, but the fundamental approach of using the MVCD (table 2) to manage a vegetation program is still problematic. These values are flashover distances and are way too close. This is acknowledged in a footnote to table 2 but no identification of allowable buffers/distances between energized phase conductors at rated temperatures and vegetation is discussed (this is left up the transmission owners). Clarity is needed on this topic. Setting a finite distance limit based on recognized standards, good science and risk avoidance should be done for the industry. BPA has previously made this comment during the drafting of the

Voter	Entity	Segment	Vote	Comment
				standard. It was not addressed then, nor has it been addressed now.
Response: The SDT thanks you for your comments. The footnotes were changed to conform with your suggestions. With respect to comments about the MVCD, R3 does not suggest the MVCD be used as a distance to manage vegetation. The MVCD was established as a beginning of a series of "building blocks" for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions. R3 requires that a Transmission Owner consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this "building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD In a performance based standard, requirements are focused on "what" needs to be accomplished to achieve desired results and avoids prescriptive requirements of "how" to achieve that result. TO's are in the best position to determine the appropriate management approach suited for their system, rather than a "one size fits all" that could suppress best practices for vegetation management.				
Randall McCamish	City of Vero Beach	1	Negative	Vero Beach's concern is that entities may not be able prove compliance with the standard. R1 and R2 say that: "Each Transmission Owner shall manage vegetation to prevent encroachments ...". If the requirements were interpreted such that "manage" is the operative word, then, we are OK because we can provide evidence of managing a program, such as a vegetation management plan and evidence of executing that plan (which does not align with the Measures). However, that 1) would cause the standard to not be performance based, and 2) it would be duplicative of the other requirements of the standard. If the requirements were interpreted with "prevent encroachment" as the operative phrase (which would be an

Voter	Entity	Segment	Vote	Comment
				incorrect interpretation from the construct of the sentence) there is no way to provide sufficient evidence that encroachment was prevented during the audit-period. The suggested Measures are not sufficient evidence to prove compliance with that interpretation of the requirement. For instance, most encroachments do not result in outages; hence, lack of outages cannot prove that there were no encroachments, and real time observations are insufficient because it is a spot-check that does not cover the audit period. There are other weaknesses in the standard, such as R4 being un-measurable therefore unenforceable. However, in the guilty until proven innocent paradigm we live in, FMPA's primary concern is that industry could be put into a no-win situation of not being able to prove compliance with the standard if R1 and R2 are interpreted as "prevent encroachment", and if R1 and R2 are interpreted as "manage" then it is not a performance based standard as advertised. Vero Beach suggests one of two approaches: 1. Performance based focused on preventing vegetation related outages. For instance: "Each Transmission Owner shall prevent vegetation related outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. 2. Modify the standard to be similar to the currently mandatory non-results based standard and focus on the word "manage". This would essentially mean eliminating R1

Voter	Entity	Segment	Vote	Comment
				and R2 since the rest of the standard focuses on having a plan and managing to that plan.
Response: The SDT thanks you for your comments. In Order 693, FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.				
Danny McDaniel	Cleco Power LLC	1	Negative	Cleco disagrees with the SDT revising the definition for Right-of-Way (ROW). Right-of-Way is a term that has had a consistent meaning throughout history. If NERC tries to redefine the term, it will only add confusion because most entities will not reference the NERC glossary for a term which is widely used in the industry. In lieu of "Active Transmission Line ROW", please use another term such as Transmission Corridor. No assumptions would be made when reading in the Standard the the Entity is to maintain vegetation located within the Transmission Corridor. Since the term is not commonly used, the NERC glossary would be referenced. Also, Cleco disagrees that an encroachment into the MCVD that does not cause an outage should be considered non-compliant as stated in R1 and R2. The encroachment should only be reportable similar to misoperations as is in the PRC-004 standard.
Response: Thank you for your comments. The existing ROW definition in the glossary was created by and for the FAC-003-1 and was moved there when that standard was adopted. The definition includes a series of options that give the Transmission Owner latitude in establishing ROW width. It does not require selecting a single method for its system. The term "blowout standard" is not capitalized and is not a defined				

Voter	Entity	Segment	Vote	Comment
term. This phrase in the definition allows a Transmission Owner to use its internal engineering standards or the general engineering standards that were in effect when the line was constructed to determine the ROW width. The SDT has limited the definition of Right-of-Way to a corridor of land with a defined width to operate a transmission line. This does not include danger tree rights. The definition of the MVCD is now added to this Standard. While use of the pre-2007 records is a compliance issue and is not in the purview of the SDT, it is the intent of the language in the definition that you could use this information. Regarding your second comment, R3 does not suggest the MVCD be used as a distance to manage vegetation. The MVCD was established as a beginning of a series of “building blocks” for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions. R3 requires that a Transmission Owner consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner’s overall vegetation management approach. The net result of this “building block” approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD Other related requirements of this “Defense in Depth” Standard serve to address any number of scenarios which may arise or hinder the TO’s ability to always strictly adhere to the management approach(s) established within R3. Thus the other requirements of this Standard provide the latitude for appropriate actions to remedy the condition without penalty. Further, trees which have encroached inside the MVCD are evidence of a deficiency in vegetation maintenance.				
Christopher L de Graffenried	Consolidated Edison Co. of New York	1	Affirmative	Reply to Question 5 on Comment Form: The added language for the annual work plan percentage complete calculation is shown in R7 not M7 as stated in the question. In the Guideline and Technical Basis Section for Requirement R6, there is a sample calculation shown for the amount of lines the TO failed to inspect. An example should also be included for Requirement R7 since there is some confusion regarding how modifications to the work plan affect the calculation. In the Lower VSL column for R7, it states that the TO failed to complete up to 5% of its annual vegetation work plan (including modifications if any). If a TO operates 100 lines and submits a justified modification that affects 10 miles of

Voter	Entity	Segment	Vote	Comment
				lines, the total number of units in the final amended plan is 90 miles. When you read the VSL, it is somewhat confusing since the information in parenthesis says that the calculation 'includes' the modifications. Should it state 'excludes modifications if any' or the VSLs can simply be re-written to state that ..The TO failed to complete up to x% of the final amended plan.' Also, the VSLs in R6 and R7 should be consistent with each other: R6 says '...TO failed to inspect 5% or less.....' and R7 says '...TO failed to complete up to 5%....' They both should use the same verbiage in each VSL whether it is 'x% or less' or 'up to and including x%.'
Response: The SDT thanks you for your comments. The percentage should be based on the plan as modified. The SDT has changed the language in the standard to reflect this more clearly, and has modified the VSLs to be consistent as you have suggested.				
Robert Martinko	FirstEnergy Energy Delivery	1	Affirmative	FirstEnergy supports standard FAC-003-2 and would appreciate consideration of our comments submitted through the formal comment period.
Response: The SDT thanks you for your comments. Please see our consideration of your comments within the responses to the formal comments.				
Luther E. Fair	Gainesville Regional Utilities	1	Negative	1. It would seem that the impetus for FAC003 is to eliminate vegetation related outages within the rights-of-way as defined and subject to the exclusions as stated in footnote 2. Thus the requirement is to manage the ROW to prevent vegetation related sustained outages with the measure being no outages. With grow-ins and fall-ins from within the defined ROW being controllable factors.

Voter	Entity	Segment	Vote	Comment
				2. Including encroachments leaves the door open for fines to be imposed with no actual outage(s) having occurred. This may be like being found guilty of a crime that has not yet taken place. 3. Combine vegetation related sustained outages by "grow-ins" and "blowing together of lines and vegetation located inside the ROW" as one item as they are both consequences of the growth of vegetation either vertically and horizontally. 4. Leave vegetation related sustained outages by "fall-in" as a standalone as this will be related to structural problems occurring from a variety of sources. 5. Combine R3 and R7 to R1 (development and implementation of a Transmission Vegetation Management Plan which shall include documented maintenance strategies or procedures or processes or specifications, delineation of an annual work plan and completion of same). Thus this would be the competency based requirements as a program without execution is meaningless. 6. R1 and R2 become R2 and R3.
Response: The SDT thanks you for your comments. In Order 693, FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct				

Voter	Entity	Segment	Vote	Comment
inspections in which clearances are evaluated.				
Ted E Hobson	JEA	1	Negative	Need to align the "measures" with the standard requirement language and the performance-based philosophy.
Response: The SDT thanks you for your comments. We are not quite clear as to what misalignment you refer to between the standard language and the measures. The SDT went to great lengths to ensure continuity between the requirements and the measures. While this standard was a first attempt at a "Results Based" approach, the SDT did have limitation in deciding what could be excluded from the standard. This standard has a mixture of the three types of requirements that comprise a results based approach: 1) Performance Based 2) Risk Based and 3) Competency Based. Having only performance-based requirements would not have resulted in a comprehensive, proactive standard.				
Michael Gammon	Kansas City Power & Light Co.	1	Negative	The Standard lacks clarity regarding the facilities that are subject to Requirement 7. It is important that a Standard be clear and not introduce ambiguity or confusion. There are several references throughout the Standard to "for all applicable lines" and it should be made clear the work plan is specific to "all applicable lines".
Response: The SDT thanks you for your comments. The team has made the appropriate modifications where necessary.				
Stan T. Rzad	Keys Energy Services	1	Negative	Concern is that entities may not be able prove compliance with the standard. R1 and R2 say that: "Each Transmission Owner shall manage vegetation to prevent encroachments ...". If the requirements were interpreted such that "manage" is the operative word, then, we are OK because we can provide evidence of managing a program, such as a vegetation management plan and evidence of executing that plan (which does not align with the Measures). However, that 1) would cause the standard to not be performance based, and 2) it would be duplicative of the

Voter	Entity	Segment	Vote	Comment
				other requirements of the standard. If the requirements were interpreted with "prevent encroachment" as the operative phrase (which would be an incorrect interpretation from the construct of the sentence) there is no way to provide sufficient evidence that encroachment was prevented during the audit-period. The suggested Measures are not sufficient evidence to prove compliance with that interpretation of the requirement. For instance, most encroachments do not result in outages; hence, lack of outages cannot prove that there were no encroachments, and real time observations are insufficient because it is a spot-check that does not cover the audit period. There are other weaknesses in the standard, such as R4 being un-measurable therefore unenforceable. However, in the guilty until proven innocent paradigm we live in, FMPA's primary concern is that industry could be put into a no-win situation of not being able to prove compliance with the standard if R1 and R2 are interpreted as "prevent encroachment", and if R1 and R2 are interpreted as "manage" then it is not a performance based standard as advertised. One of two approaches are suggested: Performance based focused on preventing vegetation related outages. For instance: "Each Transmission Owner shall prevent vegetation related outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. Modify the standard to be similar to the currently mandatory

Voter	Entity	Segment	Vote	Comment
				non-results based standard and focus on the word "manage". This would essentially mean eliminating R1 and R2 since the rest of the standard focuses on having a plan and managing to that plan.
Response: The SDT thanks you for your comments. In Order 693, FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.				
Walt Gill	Lake Worth Utilities	1	Negative	CLWU's concern is that entities may not be able prove compliance with the standard. R1 and R2 say that: "Each Transmission Owner shall manage vegetation to prevent encroachments ...". If the requirements were interpreted such that "manage" is the operative word, then, we are OK because we can provide evidence of managing a program, such as a vegetation management plan and evidence of executing that plan (which does not align with the Measures). However, that 1) would cause the standard to not be performance based, and 2) it would be duplicative of the other requirements of the standard. If the requirements were interpreted with "prevent encroachment" as the operative phrase (which would be an incorrect interpretation from the construct of the sentence) there is no way to provide sufficient evidence that encroachment was prevented during the audit-period. The suggested Measures are not sufficient evidence to prove compliance with that interpretation of the requirement. For instance, most encroachments do not result in outages; hence, lack of outages cannot prove that there were no

Voter	Entity	Segment	Vote	Comment
				encroachments, and real time observations are insufficient because it is a spot-check that does not cover the audit period. There are other weaknesses in the standard, such as R4 being un-measurable therefore unenforceable. However, in the guilty until proven innocent paradigm we live in, FMPA's primary concern is that industry could be put into a no-win situation of not being able to prove compliance with the standard if R1 and R2 are interpreted as "prevent encroachment", and if R1 and R2 are interpreted as "manage" then it is not a performance based standard as advertised. CLWU suggests one of two approaches: 1. Performance based focused on preventing vegetation related outages. For instance: "Each Transmission Owner shall prevent vegetation related outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. 2. Modify the standard to be similar to the currently mandatory non-results based standard and focus on the word "manage". This would essentially mean eliminating R1 and R2 since the rest of the standard focuses on having a plan and managing to that plan..

Response: The SDT thanks you for your comments. In Order 693, FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.

Voter	Entity	Segment	Vote	Comment
Saurabh Saksena	National Grid	1	Affirmative	The revised ROW definition emphasizes the ROW width needed to operate the transmission line(s). It is National Grid's interpretation that the width established when the line was constructed is the width to be maintained. This width is documented in engineering drawings, per-2007 vegetation records or blow-out standards. This definition does not imply that danger tree rights beyond the constructed and maintained width are incorporated in the definition; therefore fallins - from outside the ROW but within an area with danger tree rights would not be considered fallin-ins from within the ROW. National Grid would like the SDT to comment on this interpretation in its response to these comments.
Response: Your interpretation is consistent with the intent of the definition that the SDT provided. However the definition includes a series of options that give the Transmission Owner latitude in establishing ROW width. It does not require selecting a single method for its system. This phrase in the definition allows a TO to use its internal engineering standards or the general engineering standards that were in effect when the line was constructed to determine the ROW width. The SDT has limited the definition of Right-of-Way to a corridor of land with a defined width to operate a transmission line. This does not include danger tree rights.				
Michael T. Quinn	Oncor Electric Delivery	1	Affirmative	In footnote 2 (pg. 8) and 4 (page 10), the wording "arboricultural activities or horticultural or agricultural activities" should be deleted and replaced with "or removal of, installation of, or digging around vegetation."
Response: The SDT thanks you for your comments. The footnotes have been changed.				
John C. Collins	Platte River Power Authority	1	Negative	Vegetation Inspection: Is the intent of "... and those vegetation conditions under the TO's control" to clarify that an entity must have ownership of the transmission line and right-of-way in addition to maintenance or operational responsibility (control), or something different? In situations

Voter	Entity	Segment	Vote	Comment
				where a TO owns one circuit on a double circuit, but the other circuit, facilities and ROW belong to another TO who has maintenance, and vegetation management responsibility, who would be responsible for violations? If the definition was modified to allow both maintenance and vegetation inspections to be performed concurrently, the intent might be clearer if it read: “This may be combined with other line inspections”, or “This may be combined with a maintenance inspection” opposed to a general line inspection. R1 and R2: Does R1 correlate to facilities in 4.2.2. and 4.2.3. (overhead transmission lines operated below 200 kV) and R2 correlate to facilities in 4.2.1. (overhead transmission lines operated at 200kV or higher)? It isn’t clear why the two requirements are split. Could it be one requirement which reads “...identified as a facility in Section 4.2”? R4: Our current imminent threat procedure requires a call to the Manager who confirms the existence of a vegetation condition that is likely to cause a Fault at any moment prior to notifying the control center. We assume notification, without any intentional time delay, would take place after managerial confirmation but feel like the enforcement authorities could interpret this differently based on how it is written in R4. If the intent of the requirement is how we interpret it, the requirement might be clearer if it read: After a Transmission Owner has confirmed a vegetation condition likely to cause a Fault at any moment, they shall notify the control center holding switching authority for the associated applicable transmission line, without any

Voter	Entity	Segment	Vote	Comment
				intentional delay.
Response: The SDT thanks you for your comment. With regard to responsibility for a violation, the TO is the accountable party even if it has an agreement with another TO to inspect and manage vegetation. With regard to your suggestion in changing the definition of Vegetation Inspection, the SDT does not believe the proposed changes are necessary for the definition to be clear. With regard to R1 and R2, they applicability applies to 4.2.1 thru 4.2.3. The distinction between the requirement is R1 applies to all lines designated as having an Interconnection Reliability Operating Limit (IROL) in the planning horizon by the Planning Coordinator; or lines designated as Major Western Electricity Coordinating Council (WECC) transfer path(s). With regard to your imminent threat procedure, the standard is not prescriptive to define a TO's imminent threat procedure. So, if your procedure includes managerial confirmation, then this would not be considered intentional delay.				
Sammy Roberts	Progress Energy Carolinas	1	Affirmative	There needs to be a change in the footnote 2 and footnote 4 to remove the exemption for "arboricultural activities or horticultural or agricultural activities" and replace it with the term "or installation of."
Response: The SDT thanks you for your comments. The footnotes have been changed.				
Laurie Williams	Public Service Company of New Mexico	1	Negative	PNM is voting negative but offers the following comments to improve the standard. 1. The last sentence of the Background on page 7 states: Thus, this Standard's emphasis is on vegetation grow-ins. However, R1 says that we shall manage encroachments as follows: R1. Each Transmission Owner shall manage vegetation to prevent encroachment that could result in a Sustained Outage encroachments of the types shown

Voter	Entity	Segment	Vote	Comment
				below, into the Minimum Vegetation Clearance Distance (MVCD) of....... 2. An encroachment due to a fall-in from inside the active transmission line Right-of-Way (ROW) that caused a vegetation-related Sustained Outage, This seems contradictory. 2. Fac-003-2 makes reference to FAC-014 and a “Planning Coordinator” in section 4.2.2 of Applicability: pg 5 see below: 4.2.2. Overhead transmission lines operated below 200kV having been identified as included in the definition of an Interconnection Reliability Operating Limit (IROL) under NERC Standard FAC-014 by the Planning Coordinator. In addition, on pg 8, R1 of FAC-003-2 makes reference to the “planning coordinator” However, FAC-014 makes no reference, or at least it is inconsistent, to a “Planning Coordinator” See below: Taken from FAC-014 4. Applicability 4.1. Reliability Coordinator 4.2. Planning Authority 4.3. Transmission Planner 4.4. Transmission Operator The terminology and definitions seem to be inconsistent.

Voter	Entity	Segment	Vote	Comment
				3. R1 and R2 are the same requirements with different applicabilities. R1 applies to lines that are connected to WECC, IROL, etc. R2 applies to all other applicable lines that are NOT an element of WECC or IROL. My Question is: If the line is not part of WECC or IROL or any other connection then, how is it applicable to the Standard? 4. R7 says the TO shall complete a %100 of annual plan but allows for modifications that include: Change in expected growth rate/ environmental factors Major storms Circumstances that are beyond the control of a Transmission Owner5 Rescheduling work between growing seasons Crew or contractor availability/ Mutual assistance agreements Identified unanticipated high priority work Weather conditions/Accessibility Permitting delays Land ownership changes/Change in land use by the landowner Funding adjustments (increase or decrease) Emerging technologies [VRF - Medium] [Time Horizon - Operations Planning] The requirement says we shall complete a %100 of the annual plan however, some of the modifications have historically taken over a year to mitigate. SHALL should be

Voter	Entity	Segment	Vote	Comment
				replaced with SHOULD with acceptable modifications and without compromising integrity of system.
Response: The SDT thanks you for your comments. Item 1: It is intended that the Standard will cover any situation within the ROW that causes an encroachment into the MVCD including fall-ins, grow-ins or blowing-together. The arrangement of the Violation Severity Levels for R1. and R2. emphasize that a grow-in results in the greatest risk to a power system, and also is the most egregious and severe failure to meet the intent of these requirements. Item 2: The term Planning Authority (PA) included in FAC-014 was replaced by NERC in the functional model Version 5 with Planning Coordinator. Where references to PA are included in legacy Standards, Planning Coordinator is now used as follows Planning Coordinator (Planning Authority). Obviously, proposed new Standards or versions must use the currently accepted terms. Item 3: R1 and R2 are dealing with the differentiation between lines that fall into IROL/WECC Transfer Path definition and those lines that do not. Keep in mind that this standard refers to all transmission lines over 200-kV. Item 4: The SDT believes replacing the word "shall" with the word "should" in Requirement 7 changes the requirement to a recommendation.				
Pawel Krupa	Seattle City Light	1	Affirmative	The revisions to the proposed FAC-003-2 Standards produced a better version through greater clarity, appropriate pragmatism, and technical foundation; A few good points that highlight this follow: 1. Definition of Terms Used in Standard: The revised definition of Right-of-Way (ROW) establishes the width of the corridor from a technical basis with the following statement "The width of the corridor is established by engineering or construction standards..." 2. Introduction, Applicability, Section 4.2 Facilities: Section 4.2.4 which pertains to substations clarifies that this standard does not apply to applicable transmission lines, inside the substation, just to "any portion of the span of the

Voter	Entity	Segment	Vote	Comment
				transmission line that is crossing the substation fence". 3. Requirements and Measures: Requirement 1 underscores sensible purpose by replacing the wording of "preventing outages from vegetation" to "manage vegetation to prevent encroachments..." 4. Guideline and Technical Basis Section: Requirement 7 contains a great practicle reference explanation as it pertains to the annual work plan. Requirement 7 explains: ..." the vegetation management approach should use the full extent of the Transmission Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management in the long term because it reduces the overall potential for encroachment, and it ensures that future planned work and future planned inspection cycles are sufficient".
Response: The SDT thanks you for your comments.				
William G. Hutchison	Southern Illinois Power Coop.	1	Negative	I beleive that the reliability region should have the right to exclude lines below 200KV. Not all lines above 100KV negative impact the BES.
Response: The SDT thanks you for your comment. This issue is presently before FERC and NERC and is outside the scope of the SDT.				
Keith V Carman	Tri-State G & T Association, Inc.	1	Affirmative	There needs to be a change in the footnote 2 and footnote 4 to remove the exemption for “arboricultural activities or horticultural or agricultural activities” and replace it with the term “ installation of”.

Voter	Entity	Segment	Vote	Comment
Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.				
Brandy A Dunn	Western Area Power Administration	1	Affirmative	There needs to be a change in the footnote 2 and footnote 4 to remove the exemption for "arboricultural activities or horticultural or agricultural activities" and replace it with the term " installation of"
Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.				
Gregory L Pieper	Xcel Energy, Inc.	1	Affirmative	Xcel Energy still believes the requirement in R6 that mandates an annual inspection is an ineffective approach and may actually go against the Commission's determination in FERC Order No. 693. The drafting team's response to our last round of comments on this issue was that "...the SDT was directed by Order 693 to set a minimum inspection criteria". It is clear in Order 693 that the Commission is not satisfied with allowing entities to choose their own inspection cycles, as the standard currently allows. However, we fail to see where the Commission mandated a minimum inspection cycle to be uniformly applied continent-wide. We urge the drafting team to revisit paragraphs 719 through 721 of Order 693. According to paragraph 721, the Commission recognizes that unique intervals by region, "based on local factors", are reasonable and appropriate. By use of the plural term "cycles", FERC anticipates the resolution may include multiple inspection cycles. Furthermore, in paragraph 719, FERC acknowledges that a minimum inspection cycle may not be the only way to address their concern. In fact, mandating an annual inspection cycle may actually go against the Commission's guidance in paragraph 720. Here is an excerpt: "...the

Voter	Entity	Segment	Vote	Comment
				Commission is dissuaded from requiring the ERO to create a backstop inspection cycle at this time. Instead, the Commission agrees that an entity's vegetation management program should be tailored to anticipated growth in the region and take into account other environmental factors. The goal is to assure that transmission owners conduct inspections at reasonable intervals." As an alternative, we propose a mid-cycle inspection. A mid-cycle inspection is based on an interval that is justified with data and technical expertise. A mid-cycle inspection would still require entities to conduct inspections at a specified interval, while allowing for differences based upon "physical and geographic factors". Not only would this approach fully address the Commissions concerns, but it would take into account the interests of stakeholders, landowners and rate-payers. We recognize that a mid-cycle inspection interval is not as easy to audit as an annual requirement, but it is a far more practical and cost-effective approach that, when applied based on an entity's expertise with its own facilities, ensures reliability.
Response: The SDT thanks you for your comments. The SDT recognizes that a number of Transmission Owners in North America may prefer to set their own inspection intervals. The SDT can also see attractiveness for a mid-cycle inspection concept; however, this introduces new complexities in planning, documentation and auditing. Because there is substantial industry support for an annual inspection interval the SDT believes that the industry is best served with this approach.				
Mark B Thompson	Alberta Electric System Operator	2	Abstain	Due to slow vegetation growth rates in many parts of Alberta, not all transmission right-of-ways require annual inspection as required in R6. TOs should be able to include planned inspection cycles in their Transmission Vegetation Management Plan.

Voter	Entity	Segment	Vote	Comment
Response: The SDT thanks you for your comments. In FERC Order 693, para. 721, FERC stated, “The Commission continues to be concerned with leaving complete discretion to the transmission owners in determining inspection cycles, which limits the effectiveness of the Reliability Standard.” The SDT established an inspection cycle at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW. There was a survey of the industry in a previous request for comments to this standard. The response to that survey is the basis for the use of the 1-year period. While there was a range of growth rates across the continent, the SDT had sufficient feedback to recommend the 1-year cycle. The inspection also would cover inspecting for fall-in threats. Please note that vegetation inspections can also be combined with other line inspections.				
Alden Briggs	New Brunswick System Operator	2	Affirmative	The term “encroachment” has to be defined, and the use of that term and the clearances required clarification. The Table listing the clearances also needed clarification.
Response: The SDT thanks you for your comment. The SDT endorses the standard dictionary definition of the term “encroachment” and as such it does not require a NERC-specific definition. The use of encroachment regarding the clearance table is explained in detail in the Technical Reference Document.”				
Richard J. Mandes	Alabama Power Company	3	Affirmative	There needs to be a change in the footnote 2 and footnote 4 to remove the exemption for “arboricultural activities or horticultural or agricultural activities” and replace it with the term “ installation of”.
Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.				
Steven Norris	APS	3	Negative	The objective, as written, is about outages that can lead to cascading and not about reliability. Recommended change to Standard Objective: To maintain a reliable electric transmission system, implement a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW.

Voter	Entity	Segment	Vote	Comment
Response: The SDT thanks you for your comment. With respect to the Purpose as written in the proposed standard, the language clearly states "To improve the reliability of the electric Transmission system…". The SDT made it a point to keep the Purpose as concise as possible without getting into issues that are covered further in the body of the standard.				
Rebecca Berdahl	Bonneville Power Administration	3	Affirmative	In R1 and R2 and their associated VSLs, the SDT added the phrase "in order of increasing severity" and added the sentence, "The types of encroachments are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO's vegetation maintenance program." to the Rationale boxes for R1/R2. Do you agree? If answer is no, please explain. BPA prefers the stratified levels of violation severity presented in the table for R1 and R2. Foot note # 2 on page 8 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. Foot note # 4 on page 12 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. In response to comments received that requirement R3 is unclear with respect to intent, the SDT added "maintenance strategies." Do you agree this clarifies the intent? If answer is no, please offer alternative language. The TO procedures / policies and specifications shall demonstrate the TO's ability to manage the system at all rated conditions to maintain reliability. BPA believes that the intent is clear, but the fundamental approach of using the MVCD (table 2) to manage a vegetation program is still

Voter	Entity	Segment	Vote	Comment
				problematic. These values are flashover distances and are way too close. This is acknowledged in a footnote to table 2 but no identification of allowable buffers/distances between energized phase conductors at rated temperatures and vegetation is discussed (this is left up the transmission owners). Clarity is needed on this topic. Setting a finite distance limit based on recognized standards, good science and risk avoidance should be done for the industry. BPA has previously made this comment during the drafting of the standard. It was not addressed then, nor has it been addressed now.
Response: The SDT thanks you for your comments. Footnotes #2 and #4 have been changed to reflect your suggestion to clarify arboricultural or horticultural or agricultural activities. With respect to comments about the MVCD, R3 does not suggest the MVCD be used as a distance to manage vegetation. The MVCD was established as a beginning of a series of "building blocks" for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions. R3 requires that a Transmission Owner consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this "building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD In a performance based standard, requirements are focused on "what" needs to be accomplished to achieve desired results and avoids prescriptive requirements of "how" to achieve that result. TO's are in the best position to determine the appropriate management approach suited for their system, rather than a "one size fits all" or "fill in the blank" requirement that could suppress best practices for vegetation management.				
Matt Culverhouse	City of Bartow, Florida	3	Negative	The suggested Measures are not sufficient evidence to prove compliance with that interpretation of the requirement. For instance, most encroachments do not result in outages; hence, lack of outages cannot prove that there were no encroachments, and real time observations

Voter	Entity	Segment	Vote	Comment
				are insufficient because it is a spot-check that does not cover the audit period. There are other weaknesses in the standard, such as R4 being un-measurable therefore unenforceable. However, in the guilty until proven innocent paradigm we live in, FMPA's primary concern is that industry could be put into a no-win situation of not being able to prove compliance with the standard if R1 and R2 are interpreted as "prevent encroachment", and if R1 and R2 are interpreted as "manage" then it is not a performance based standard as advertised.
Response: The SDT thanks you for your comments. In Order 693, FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated. Also please reference footnote 3.				
Bryan Y Harper	Cleco Utility Group	3	Negative	Cleco disagrees with the SDT revising the definition for Right-of-Way (ROW). Right-of-Way is a term that has had a consistent meaning throughout history. If NERC tries to redefine the term, it will only add confusion because most entities will not reference the NERC glossary for a term which is widely used in the industry. In lieu of "Active Transmission Line ROW", please use another term such as Transmission Corridor. No assumptions would be made when reading in the Standard the the Entity is to maintain vegetation located within the Transmission Corridor. Since the term is not commonly used, the NERC glossary would be referenced. Also, Cleco disagrees that an encroachment into the MCVD

Voter	Entity	Segment	Vote	Comment
				that does not cause an outage should be considered non-compliant as stated in R1 and R2. The encroachment should only be reportable similar to misoperations as is in the PRC-004 standard.

Response: Thanks for your comments. The existing ROW definition in the glossary was created by and for the FAC-003-1 and was moved there when that standard was adopted. The definition includes a series of options that give the Transmission Owner latitude in establishing ROW width. It does not require selecting a single method for its system. The term blowout standard is not capitalized and is not a defined term. This phrase in the definition allows a Transmission Owner to use its internal engineering standards or the general engineering standards that were in effect when the line was constructed to determine the ROW width. The SDT has limited the definition of Right-of-Way to a corridor of land with a defined width to operate a transmission line. This does not include danger tree rights. The definition of the MVCD is now added to this Standard. While use of the pre-2007 records is a compliance issue and is not in the purview of the SDT, it is the intent of the language in the definition that you could use this information.

Regarding your second comment, the MVCD was established as a beginning of a series of "building blocks" for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions.

R3 requires that a Transmission Owner consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this "building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD.

Other related requirements of this "Defense in Depth" Standard serve to address any number of scenarios which may arise or hinder the TO's ability to always strictly adhere to the management approach(s) established within R3. Thus the other requirements of this Standard provide the latitude for appropriate actions to remedy the condition without penalty. Further, trees which have encroached inside the MVCD are evidence of a deficiency in vegetation maintenance.

Voter	Entity	Segment	Vote	Comment
Peter T Yost	Consolidated Edison Co. of New York	3	Affirmative	Reply to Question 5 on Comment Form: The added language for the annual work plan percentage complete calculation is shown in R7 not M7 as stated in the question. In the Guideline and Technical Basis Section for Requirement R6, there is a sample calculation shown for the amount of lines the TO failed to inspect. An example should

Voter	Entity	Segment	Vote	Comment
				also be included for Requirement R7 since there is some confusion regarding how modifications to the work plan affect the calculation. In the Lower VSL column for R7, it states that the TO failed to complete up to 5% of its annual vegetation work plan (including modifications if any). If a TO operates 100 lines and submits a justified modification that affects 10 miles of lines, the total number of units in the final amended plan is 90 miles. When you read the VSL, it is somewhat confusing since the information in parenthesis says that the calculation 'includes' the modifications. Should it state 'excludes modifications if any' or the VSLs can simply be re-written to state that ..The TO failed to complete up to x% of the final amended plan.' Also, the VSLs in R6 and R7 should be consistent with each other: R6 says '...TO failed to inspect 5% or less.....' and R7 says '...TO failed to complete up to 5%....' They both should use the same verbiage in each VSL whether it is 'x% or less' or 'up to and including x%.'
Response: The SDT thanks you for your comments. Your correction is accurate. The percentage should be based on the plan as modified. The SDT has changed the language in the standard to reflect this more clearly. The VSLs have been modified to be consistent as suggested.				
David A. Lapinski	Consumers Energy	3	Negative	Comments on FAC-003-2 February 25, 2011 Consumers Energy submits the following comments on FAC-003-2: In general we are please with FAC-003-2 and the many clarifications that the STD has made in this version of the standard. However, we do have one major disagreement with the STD and cannot support this standard as drafted.

Voter	Entity	Segment	Vote	Comment
				We disagree with the use of the Minimum Vegetation Clearance Distance (MVCD) developed by the drafting team for Requirements R1 and R2. These distances are not the design distances used for designing and constructing transmission facilities as stated in the document for minimum distances between conductors and grounded objects. The proposed Table 2 provides a distance of 3.12 feet as the acceptable distance for an alternate current 345kV line at sea level. This distance is considerably less than the distance used for line design to separate the grounded tower structure from the energized conductor. If the distance in Table 2 is acceptable to prevent energized portions of a transmission line from grounding to a tree why then is this distance not the design criteria used for tower design to prevent flashover from conductor to tower? The STD needs to explain why a ground tree should have a different standard that a grounded steel tower or wood pole structure. The STD erroneously viewed the possibility of transient over voltage as only occurring during re-energizing and not from natural events such as a lightning strike that can occur and does occur to energized operating lines. Secondly, the proposed distances in Table 2 are considerably less than the distances specified in OSHA requirements for air gap clearance required by tree workers to safely remove trees or limbs from conductors energized at the voltages specified. A transmission owner/operator could let a tree grow to within 3.5 feet of a 345 kV line and not be in violation of this proposed standard. To remove the tree, the

Voter	Entity	Segment	Vote	Comment
				line would have to be de-energized, tagged, tested de-energized, and grounded. Working clearance would have to be established by the operating entity and then the tree crew could remove the tree. The net result is the loss of the capacity of the line because an outage was forced on the line in order to remove the tree that did not trigger a violation of FAC-003-2. This situation, in our opinion, is a violation of the intent of the standard, which is to ensure the continued operation of the line. Therefore, the minimum distance any tree should be able to approach a conductor is more than the minimum requirement for air gap distance between the tree and conductor as required by OSHA worker standards. The STD did not like referring to another standard to provide the distance requirements for R1 and R2. This can be alleviated by putting in a table with the IEEE 516 distances but not reference it as the IEEE 516 standard. The distances provided in the current draft do not adequately provide or ensure the continued safe operation of the transmission facilities in the United States and the reasoning for the distances provided is unfounded and not based on current design practices.

Response: The SDT thanks you for your comments. You are correct that these distances do not represent complete design specifications for towers, nor define and describe safe worker approach distances. These practices are correctly specified in the other standards you referenced. The SDT feels the standard is clear in that regard. The footnote associated with the Table 2 distances clearly states that these are only distances to prevent flashover under appropriate conditions. The SDT would also like to point out that the transient overvoltage factors used to derive these distances are the maximums normally seen with a transmission line in steady state service. Thus, a tower design would have to account for the larger overvoltage factors that are possible while taking lines out of service.

As has been stated before, these distances were derived using a known set of line design equations and only represent distances that will prevent spark-over from the transmission line to a grounded object. These are not distances to be managed to – they have been established as a beginning of a series of "building blocks" for a program to ensure reliability of a

Voter	Entity	Segment	Vote	Comment
Transmission line within its rating and all rated electrical operating conditions. R3 requires that a Transmission Owner' consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this "building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD. These distances are smaller than safety standard distances that have many other factors involved in the determination, such as inadvertent human movement and larger safety factors. In regard to the over-voltages caused by lightning, even the maximum overvoltage factors contained in the IEEE-516 tables do not account for these.				
Russell A Noble	Cowlitz County PUD	3	Negative	Referring back to Cowlitz' negative vote made on the 7/9-19/2010 ballot, Cowlitz tried to convey the problem that the statement in R4 "without intentional time delay" will require subjective judgment on the part of the auditor. In other words, maintaining equal auditing standard throughout the interconnection will be impossible with this verbiage in a requirement. Cowlitz agrees with the SDT that establishing an equitable time frame is very difficult (it may be impossible!); however leaving it to the judgment of the auditor to determine whether an intentional delay was made is most disagreeable. Cowlitz respectfully points out that the SDT did not adequately address the subjective nature the auditor is forced into with this requirement. If establishing "[t]he time required by the to report an issue is subject to many variables..." and "[f]or this reason it is difficult to establish a time period which would fairly apply to all TO's," how does leaving this to the auditor to decide going to make it any better?
Response: The SDT believes that it was not prudent to suggest a quantitative time element for notification in R4. The technical reference offers examples of acceptable unintentional delays for your review. The SDT notes that this language is already embodied in at least one other FERC-approved, in-force Standard.				

Voter	Entity	Segment	Vote	Comment
Kevin Querry	FirstEnergy Solutions	3	Affirmative	FirstEnergy supports standard FAC-003-2 and would appreciate consideration of our comments submitted through the formal comment period.
Response: The SDT thanks you for your comments. Please see our consideration of your comments within the responses to the formal comments.				
Lee Schuster	Florida Power Corporation	3	Affirmative	There needs to be a change in the footnote 2 and footnote 4 to remove the exemption for “arboricultural activities or horticultural or agricultural activities” and replace it with the term “installation of."
Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.				
Anthony L Wilson	Georgia Power Company	3	Affirmative	There needs to be a change in the footnote 2 and footnote 4 to remove the exemption for “arboricultural activities or horticultural or agricultural activities” and replace it with the term “ installation of”.
Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.				
Charles Locke	Kansas City Power & Light Co.	3	Negative	The Standard lacks clarity regarding the facilities that are subject to Requirement 7. It is important that a Standard be clear and not introduce ambiguity or confusion. There are several references throughout the Standard to "for all applicable lines" and it should be made clear the work plan is specific to "all applicable lines".
Response: The SDT thanks you for your comments. The team has made the appropriate modifications where necessary.				
Mace Hunter	Lakeland Electric	3	Affirmative	R1. Each Transmission Owner shall manage vegetation to prevent encroachments of the types shown below, ------------

Voter	Entity	Segment	Vote	Comment
				---- and all Rated Electrical Operating Conditions.2 1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage, that is not corrected within 5 working days of discovery, Make the same change to R2 Type 1 encroachment and reflect the changes in Table 1. Rational: This condition would enable a entity to discover an encroachment and clear it without having to self report a possible violation as long as the conditions was corrected within 5 working days. The change should encourage extra inspections for problem areas more often than annually as required in R6. There should be no negative consequences for diligent inspection of lines as long as the problem is clear with a defined time such as 5 or 10 working days.
Response: The SDT thanks you for your comment. As a general rule, a revised standard should not be less stringent than the existing standard it replaces. In the existing standard, a violation occurs when the encroachment occurs. A 'find and fix' of five days would be viewed as a lowering of the level of required performance established by the current standard.				
Bruce Merrill	Lincoln Electric System	3	Affirmative	While supportive of the drafting team's efforts, LES believes a change is warranted in Footnote 2 and Footnote 4 to remove the exemption for "arboricultural activities or horticultural or agricultural activities" and replace with the term "installation of". As currently drafted, the wording could potentially be construed to mean that the TO would or could be constrained or refused permission to prune and remove any and all vegetation in the ROW in accordance with the full legal rights of the ROW agreement(s).
Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.				
Don Horsley	Mississippi Power	3	Affirmative	There needs to be a change in the footnote 2 and footnote 4 to remove the exemption for "arboricultural activities or

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				horticultural or agricultural activities" and replace it with the term " installation of".
Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.				
Terry L Baker	Platte River Power Authority	3	Negative	FAC-003-2 Comments Vegetation Inspection: Is the intent of "... and those vegetation conditions under the TO's control" to clarify that an entity must have ownership of the transmission line and right-of-way in addition to maintenance or operational responsibility (control), or something different? In situations where a TO owns one circuit on a double circuit, but the other circuit, facilities and ROW belong to another TO who has maintenance, and vegetation management responsibility, who would be responsible for violations? If the definition was modified to allow both maintenance and vegetation inspections to be performed concurrently, the intent might be clearer if it read: "This may be combined with other line inspections", or "This may be combined with a maintenance inspection" opposed to a general line inspection. R1 and R2: Does R1 correlate to facilities in 4.2.2. and 4.2.3. (overhead transmission lines operated below 200 kV) and R2 correlate to facilities in 4.2.1. (overhead transmission lines operated at 200kV or higher)? It isn't clear why the two requirements are split. Could it be one requirement which reads "...identified as a facility in Section 4.2"? R4: Our current imminent threat procedure requires a call

Voter	Entity	Segment	Vote	Comment
				to the Manager who confirms the existence of a vegetation condition that is likely to cause a Fault at any moment prior to notifying the control center. We assume notification, without any intentional time delay, would take place after managerial confirmation but feel like the enforcement authorities could interpret this differently based on how it is written in R4. If the intent of the requirement is how we interpret it, the requirement might be clearer if it read: After a Transmission Owner has confirmed a vegetation condition likely to cause a Fault at any moment, they shall notify the control center holding switching authority for the associated applicable transmission line, without any intentional delay.
Response: The SDT thanks you for your comment. With regard to responsibility for a violation, the TO is the accountable party even if it has an agreement with another TO to inspect and manage vegetation. With regard to your suggestion in changing the definition of Vegetation Inspection, the SDT does not believe the proposed changes are necessary for the definition to be clear. With regard to R1 and R2, they applicability applies to 4.2.1 thru 4.2.3. The distinction between the requirement is R1 applies to all lines designated as having an Interconnection Reliability Operating Limit (IROL) in the planning horizon by the Planning Coordinator; or lines designated as Major Western Electricity Coordinating Council (WECC) transfer path(s). With regard to your imminent threat procedure, the standard is not prescriptive to define a TO's imminent threat procedure. So, if your procedure includes managerial confirmation, then this would not be considered intentional delay.				
Dana Wheelock	Seattle City Light	3	Affirmative	The revisions to the proposed FAC-003-2 Standards produced a better version through greater clarity, appropriate pragmatism, and technical foundation; A few good points that highlight this follow: 1. Definition of Terms Used in Standard: The revised definition of Right-of-Way (ROW) establishes the width of the corridor from a technical basis with the following

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				statement "The width of the corridor is established by engineering or construction standards..." 2. Introduction, Applicability, Section 4.2 Facilities: Section 4.2.4 which pertains to substations clarifies that this standard does not apply to applicable transmission lines, inside the substation, just to "any portion of the span of the transmission line that is crossing the substation fence". 3. Requirements and Measures: Requirement 1 underscores sensible purpose by replacing the wording of "preventing outages from vegetation" to "manage vegetation to prevent encroachments..." 4. Guideline and Technical Basis Section: Requirement 7 contains a great practicle reference explanation as it pertains to the annual work plan. Requirement 7 explains: ..." the vegetation management approach should use the full extent of the Transmission Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management in the long term because it reduces the overall potential for encroachment, and it ensures that future planned work and future planned inspection cycles are sufficient".
Response: The SDT thanks you for your comments.				
Michael Ibold	Xcel Energy, Inc.	3	Affirmative	Xcel Energy still believes the requirement in R6 that mandates an annual inspection is an ineffective approach and may actually go against the Commission’s

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				determination in FERC Order No. 693. The drafting team's response to our last round of comments on this issue was that "...the SDT was directed by Order 693 to set a minimum inspection criteria". It is clear in Order 693 that the Commission is not satisfied with allowing entities to choose their own inspection cycles, as the standard currently allows. However, we fail to see where the Commission mandated a minimum inspection cycle to be uniformly applied continent-wide. We urge the drafting team to revisit paragraphs 719 through 721 of Order 693. According to paragraph 721, the Commission recognizes that unique intervals by region, "based on local factors", are reasonable and appropriate. By use of the plural term "cycles", FERC anticipates the resolution may include multiple inspection cycles. Furthermore, in paragraph 719, FERC acknowledges that a minimum inspection cycle may not be the only way to address their concern. In fact, mandating an annual inspection cycle may actually go against the Commission's guidance in paragraph 720. Here is an excerpt: "...the Commission is dissuaded from requiring the ERO to create a backstop inspection cycle at this time. Instead, the Commission agrees that an entity's vegetation management program should be tailored to anticipated growth in the region and take into account other environmental factors. The goal is to assure that transmission owners conduct inspections at reasonable intervals." As an alternative, we propose a mid-cycle inspection. A mid-cycle inspection is based on an interval that is justified with data and technical expertise. A mid-cycle inspection would still require entities to conduct inspections at a specified interval, while allowing for differences based upon "physical

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				and geographic factors". Not only would this approach fully address the Commissions concerns, but it would take into account the interests of stakeholders, landowners and rate-payers. We recognize that a mid-cycle inspection interval is not as easy to audit as an annual requirement, but it is a far more practical and cost-effective approach that, when applied based on an entity's expertise with its own facilities, ensures reliability.
Response: The SDT thanks you for your comments. The SDT recognizes that a number of Transmission Owners in North America may prefer to set their own inspection intervals. The SDT can also see attractiveness for a mid-cycle inspection concept; however, this introduces new complexities in planning, documentation and auditing. Because there is substantial industry support for an annual inspection interval the SDT believes that the industry is best served with this approach.				
Rick Syring	Cowlitz County PUD	4	Negative	Referring back to Cowlitz' negative vote made on the 7/9-19/2010 ballot, Cowlitz tried to convey the problem that the statement in R4 "without intentional time delay" will require subjective judgment on the part of the auditor. In other words, maintaining equal auditing standard throughout the interconnection will be impossible with this verbiage in a requirement. Cowlitz agrees with the SDT that establishing an equitable time frame is very difficult (it may be impossible!); however leaving it to the judgment of the auditor to determine whether an intentional delay was made is most disagreeable. Cowlitz respectfully points out that the SDT did not adequately address the subjective nature the auditor is forced into with this requirement. If "[t]he time required by the entity to report an issue is subject to many variables..." and "[f]or this reason it is difficult to establish a time period which would fairly apply to all TO's," how does leaving this to the auditor to decide going to make it any better? You will be forcing the audited entity to "prove the negative."

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Response: The SDT believes that it was not prudent to suggest a quantitative time element for notification in R4. The technical reference offers examples of acceptable unintentional delays for your review. The SDT notes that this language is already embodied in at least one other FERC-approved, in-force Standard.				
Frank Gaffney	Florida Municipal Power Agency	4	Negative	R1 and R2 requirement reads: "Each Transmission Owner shall manage to prevent encroachment ....". The results of manage would be invoices of tree trimming actually performed, documentation of a vegetation management program that would be managed to, etc. However, the Measures proposed are all actual outages which are neither evidence of management nor evidence of encroachment since there can be encroachment without an outage, and in fact, many if not most encroachments do not result in outages. Hence, the Measures are inconsistent with the requirements. Further, there is ambiguity of the action required in requirements R1 and R2 - e.g., do entities need evidence that they: 1) "manage", or 2) "prevent encroachment"; or 3) as implied by the Measures, prevent vegetation related outages?. In other words, what needs to be proven through evidence? Certainly the third, prevent vegetation related outages, is not in the Requirement; yet, that us what is proposed for the Measures, highlighting the inconsistency between Requirements and Measures. But, how would the ambiguity between "manage" and "prevent encroachment" be resolved? One auditor could interpret that the requirement is to "manage" and accept a vegetation management program and plan and proof that the plan was executed as appropriate evidence. Another auditor could interpret that "prevent" is the key word and look for evidence proving that there was never a vegetation

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				encroachment. How would evidence be produced to provide the auditor that vegetation never encroached? Would video cameras and other surveillance measures need to operate 24 hours a day? Would we cause an entity to survey the lines periodically? One can easily see that "prevent encroachment" is inappropriate here since it is infeasible to create evidence of compliance. FMPA suggests one of two approaches: Eliminate the word manage, but do not focus on encroachment and instead focus on outages. For instance: "Each Transmission Owner shall prevent vegetation related outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. Focus on the word "manage", similar to the existing FAC-003 standard, and move R3 to a new R1 to develop a management plan, and then the existing R1 and R2 become R2 an R3 and require execution of that plan in the words of R7, which would in turn enables elimination of R7.
Response: The SDT thanks you for your comments. In Order 693, FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.				
Thomas W. Richards	Fort Pierce Utilities	4	Negative	R1 and R2 requirement reads: "Each Transmission Owner shall manage to prevent encroachment ....". The results of

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	Authority			manage would be invoices of tree trimming actually performed, documentation of a vegetation management program that would be managed to, etc. However, the Measures proposed are all actual outages which are neither evidence of management nor evidence of encroachment since there can be encroachment without an outage, and in fact, many if not most encroachments do not result in outages. Hence, the Measures are inconsistent with the requirements. Further, there is ambiguity of the action required in requirements R1 and R2 - e.g., do entities need evidence that they: 1) "manage", or 2) "prevent encroachment"; or 3) as implied by the Measures, prevent vegetation related outages?. In other words, what needs to be proven through evidence? Certainly the third, prevent vegetation related outages, is not in the Requirement; yet, that us what is proposed for the Measures, highlighting the inconsistency between Requirements and Measures. But, how would the ambiguity between "manage" and "prevent encroachment" be resolved? One auditor could interpret that the requirement is to "manage" and accept a vegetation management program and plan and proof that the plan was executed as appropriate evidence. Another auditor could interpret that "prevent" is the key word and look for evidence proving that there was never a vegetation encroachment. How would evidence be produced to provide the auditor that vegetation never encroached? Would video cameras and other surveillance measures need to operate 24 hours a day? Would we cause an entity to survey the lines periodically? One can easily see that "prevent encroachment" is inappropriate here since it is

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				infeasible to create evidence of compliance. FPUA suggests one of two approaches: 1. Eliminate the word manage, but do not focus on encroachment and instead focus on outages. For instance: "Each Transmission Owner shall prevent vegetation related outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. 2. Focus on the word "manage", similar to the existing FAC-003 standard, and move R3 to a new R1 to develop a management plan, and then the existing R1 and R2 become R2 an R3 and require execution of that plan in the words of R7, which would in turn enables elimination of R7.
Response: The SDT thanks you for your comments. In Order 693, FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.				
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Affirmative	"While supportive of the drafting team's efforts, The MGE believes a change is warranted in Footnote 2 and Footnote 4 to remove the exemption for "arboricultural activities or horticultural or agricultural activities" and replace with the term "installation of". As currently drafted, the wording could potentially be construed to mean that the TO would or could be constrained or refused permission to prune and remove any and all vegetation in the ROW in accordance

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				with the full legal rights of the ROW agreement(s).”
Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.				
Douglas Hohlbaugh	Ohio Edison Company	4	Affirmative	FirstEnergy supports standard FAC-003-2 and would appreciate consideration of our comments submitted through the formal comment period.
Response: The SDT thanks you for your comments. Please see our consideration of your comments within the responses to the formal comments.				
Hao Li	Seattle City Light	4	Affirmative	The revisions to the proposed FAC-003-2 Standards produced a better version through greater clarity, appropriate pragmatism, and technical foundation; A few good points that highlight this follow: 1. Definition of Terms Used in Standard: The revised definition of Right-of-Way (ROW) establishes the width of the corridor from a technical basis with the following statement "The width of the corridor is established by engineering or construction standards..." 2. Introduction, Applicability, Section 4.2 Facilities: Section 4.2.4 which pertains to substations clarifies that this standard does not apply to applicable transmission lines, inside the substation, just to "any portion of the span of the transmission line that is crossing the substation fence". 3. Requirements and Measures: Requirement 1 underscores sensible purpose by replacing the wording of "preventing outages from vegetation" to "manage vegetation to prevent encroachments..."

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				4. Guideline and Technical Basis Section: Requirement 7 contains a great practicle reference explanation as it pertains to the annual work plan. Requirement 7 explains: ..." the vegetation management approach should use the full extent of the Transmission Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management in the long term because it reduces the overall potential for encroachment, and it ensures that future planned work and future planned inspection cycles are sufficient".
Response: The SDT thanks you for your comments.				
Brock Ondayko	AEP Service Corp.	5	Affirmative	American Electric Power believes that the phrase "arboricultural activities or horticultural or agricultural activities" was mistakenly introduced into Footnotes 2 and 4, and should be deleted from both footnotes. If the phrase remains in the Standard, it may empower orchard growers, landowners and others to plant trees on the right of way and challenge Transmission Owners' rights to perform maintenance on the presumption that the standard will exempt the TO from violating the outage or encroachment requirements. For increased clarity, AEP offers the following change to the second paragraph of M1, as well as the second paragraph of M2. The original text “If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the

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				equivalent of a Real-time observation" should be replaced with "If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation growing into or blowing together with the conductor within the ROW, this shall be considered the equivalent of a Real-time observation. A brief encroachment caused by falling vegetation passing through the MVCD is not considered an encroachment in this requirement".
Response: Thanks you for your comments. The SDT made suggested changes. Regarding the issue of fall-ins, the SDT is sympathetic to your concern. In fact, the SDT had originally crafted language similar to that which you suggested. However, due to concerns expressed by regulators and others, the exemption for encroachment violations due to falling vegetation from inside the right of way was removed.				
Francis J. Halpin	Bonneville Power Administration	5	Affirmative	In R1 and R2 and their associated VSLs, the SDT added the phrase "in order of increasing severity" and added the sentence, "The types of encroachments are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO's vegetation maintenance program." to the Rationale boxes for R1/R2. Do you agree? If answer is no, please explain. BPA prefers the stratified levels of violation severity presented in the table for R1 and R2. Foot note # 2 on page 8 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. Foot note # 4 on page 12 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities.

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				In response to comments received that requirement R3 is unclear with respect to intent, the SDT added “maintenance strategies.” Do you agree this clarifies the intent? If answer is no, please offer alternative language. The TO procedures / policies and specifications shall demonstrate the TO’s ability to manage the system at all rated conditions to maintain reliability. BPA believes that the intent is clear, but the fundamental approach of using the MVCD (table 2) to manage a vegetation program is still problematic. These values are flashover distances and are way too close. This is acknowledged in a footnote to table 2 but no identification of allowable buffers/distances between energized phase conductors at rated temperatures and vegetation is discussed (this is left up the transmission owners). Clarity is needed on this topic. Setting a finite distance limit based on recognized standards, good science and risk avoidance should be done for the industry. BPA has previously made this comment during the drafting of the standard. It was not addressed then, nor has it been addressed now.

Response: The SDT thanks you for your comments. The footnotes were changed to conform with your suggestions.

With respect to comments about the MVCD, R3 does not suggest the MVCD be used as a distance to manage vegetation. The MVCD was established as a beginning of a series of “building blocks” for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions.

R3 requires that a Transmission Owner consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner’s overall vegetation management approach. The net result of this “building block” approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD distances.

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In a performance based standard, requirements are focused on “what” needs to be accomplished to achieve desired results and avoids prescriptive requirements of “how” to achieve that result. TO’s are in the best position to determine the appropriate management approach suited for their system rather than a “one size fits all” or “fill in the blanks” requirements that could suppress best practices for vegetation management.				
Wilket (Jack) Ng	Consolidated Edison Co. of New York	5	Affirmative	Reply to Question 5 on Comment Form: The added language for the annual work plan percentage complete calculation is shown in R7 not M7 as stated in the question. In the Guideline and Technical Basis Section for Requirement R6, there is a sample calculation shown for the amount of lines the TO failed to inspect. An example should also be included for Requirement R7 since there is some confusion regarding how modifications to the work plan affect the calculation. In the Lower VSL column for R7, it states that the TO failed to complete up to 5% of its annual vegetation work plan (including modifications if any). If a TO operates 100 lines and submits a justified modification that affects 10 miles of lines, the total number of units in the final amended plan is 90 miles. When you read the VSL, it is somewhat confusing since the information in parenthesis says that the calculation 'includes' the modifications. Should it state 'excludes modifications if any' or the VSLs can simply be re-written to state that ..The TO failed to complete up to x% of the final amended plan.' Also, the VSLs in R6 and R7 should be consistent with each other: R6 says '...TO failed to inspect 5% or less.....' and R7 says '...TO failed to complete up to 5%....' They both should use the same verbiage in each VSL whether it is 'x% or less' or 'up to and including x%.'

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Response: The SDT thanks you for your comments. The percentage should be based on the plan as modified. The SDT has changed the language in the standard to reflect this more clearly, and has modified the VSLs to be consistent as you have suggested.				
James B Lewis	Consumers Energy	5	Negative	Consumers Energy submits the following comments on FAC-003-2: In general we are please with FAC-003-2 and the many clarifications that the STD has made in this version of the standard. However, we do have one major disagreement with the STD and cannot support this standard as drafted. We disagree with the use of the Minimum Vegetation Clearance Distance (MVCD) developed by the drafting team for Requirements R1 and R2. These distances are not the design distances used for designing and constructing transmission facilities as stated in the document for minimum distances between conductors and grounded objects. The proposed Table 2 provides a distance of 3.12 feet as the acceptable distance for an alternate current 345kV line at sea level. This distance is considerably less than the distance used for line design to separate the grounded tower structure from the energized conductor. If the distance in Table 2 is acceptable to prevent energized portions of a transmission line from grounding to a tree why then is this distance not the design criteria used for tower design to prevent flashover from conductor to tower? The STD needs to explain why a ground tree should have a different standard that a grounded steel tower or wood pole structure. The STD erroneously viewed the possibility of transient over

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				voltage as only occurring during re-energizing and not from natural events such as a lightning strike that can occur and does occur to energized operating lines. Secondly, the proposed distances in Table 2 are considerably less than the distances specified in OSHA requirements for air gap clearance required by tree workers to safely remove trees or limbs from conductors energized at the voltages specified. A transmission owner/operator could let a tree grow to within 3.5 feet of a 345 kV line and not be in violation of this proposed standard. To remove the tree, the line would have to be de-energized, tagged, tested de-energized, and grounded. Working clearance would have to be established by the operating entity and then the tree crew could remove the tree. The net result is the loss of the capacity of the line because an outage was forced on the line in order to remove the tree that did not trigger a violation of FAC-003-2. This situation, in our opinion, is a violation of the intent of the standard, which is to ensure the continued operation of the line. Therefore, the minimum distance any tree should be able to approach a conductor is more than the minimum requirement for air gap distance between the tree and conductor as required by OSHA worker standards. The STD did not like referring to another standard to provide the distance requirements for R1 and R2. This can be alleviated by putting in a table with the IEEE 516 distances but not reference it as the IEEE 516 standard. The distances provided in the current draft do not adequately provide or ensure the continued safe operation of the transmission facilities in the United States and the reasoning for the distances provided is unfounded and not based on current design practices.

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Response: The SDT thanks you for your comments. You are correct that these distances do not represent complete design specifications for towers, nor define and describe safe worker approach distances. These practices are correctly specified in the other standards you referenced. The SDT feels the standard is clear in that regard. The footnote associated with the Table 2 distances clearly states that these are only distances to prevent flashover under appropriate conditions. The SDT would also like to point out that the transient overvoltage factors used to derive these distances are the maximums normally seen with a transmission line in steady state service. Thus, a tower design would have to account for the larger overvoltage factors that are possible while taking lines out of service. As has been stated before, these distances were derived using a known set of line design equations and only represent distances that will prevent spark-over from the transmission line to a grounded object. These are not distances to be managed to – they have been established as a beginning of a series of "building blocks" for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions. R3 requires that a Transmission Owner consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this "building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD. These distances are smaller than safety standard distances that have many other factors involved in the determination, such as inadvertent human movement and larger safety factors. In regard to the over-voltages caused by lightning, even the maximum overvoltage factors contained in the IEEE-516 tables do not account for these.				
Bob Essex	Cowlitz County PUD	5	Negative	Referring back to Cowlitz' negative vote made on the 7/9-19/2010 ballot, Cowlitz tried to convey the problem that the statement in R4 "without intentional time delay" will require subjective judgment on the part of the auditor. In other words, maintaining equal auditing standard throughout the interconnection will be impossible with this verbiage in a requirement. Cowlitz agrees with the SDT that establishing an equitable time frame is very difficult (it may be impossible!); however leaving it to the judgment of the auditor to determine whether an intentional delay was made is most disagreeable. Cowlitz respectfully points out that the SDT did not adequately address the subjective nature the auditor is forced into with this requirement. If

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				establishing "[t]he time required by the to report an issue is subject to many variables..." and "[f]or this reason it is difficult to establish a time period which would fairly apply to all TO's," how does leaving this to the auditor to decide going to make it any better?
Response: The SDT believes that it was not prudent to suggest a quantitative time element for notification in R4. The technical reference offers examples of acceptable unintentional delays for your review. The SDT notes that this language is already embodied in at least one other FERC-approved, in-force Standard.				
Kenneth Dresner	FirstEnergy Solutions	5	Affirmative	FirstEnergy supports standard FAC-003-2 and would appreciate consideration of our comments submitted through the formal comment period.
Response: The SDT thanks you for your comments. Please see our consideration of your comments within the responses to the formal comments.				
David Schumann	Florida Municipal Power Agency	5	Negative	R1 and R2 requirement reads: "Each Transmission Owner shall manage to prevent encroachment ....". The results of manage would be invoices of tree trimming actually performed, documentation of a vegetation management program that would be managed to, etc. However, the Measures proposed are all actual outages which are neither evidence of management nor evidence of encroachment since there can be encroachment without an outage, and in fact, many if not most encroachments do not result in outages. Hence, the Measures are inconsistent with the requirements. Further, there is ambiguity of the action required in requirements R1 and R2 - e.g., do entities need evidence that they: 1) "manage", or 2) "prevent encroachment"; or 3) as implied by the Measures, prevent vegetation related outages?. In other words, what needs to be proven through evidence? Certainly the third, prevent vegetation related

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				outages, is not in the Requirement; yet, that us what is proposed for the Measures, highlighting the inconsistency between Requirements and Measures. But, how would the ambiguity between "manage" and "prevent encroachment" be resolved? One auditor could interpret that the requirement is to "manage" and accept a vegetation management program and plan and proof that the plan was executed as appropriate evidence. Another auditor could interpret that "prevent" is the key word and look for evidence proving that there was never a vegetation encroachment. How would evidence be produced to provide the auditor that vegetation never encroached? Would video cameras and other surveillance measures need to operate 24 hours a day? Would we cause an entity to survey the lines periodically? One can easily see that "prevent encroachment" is inappropriate here since it is infeasible to create evidence of compliance. FMPA suggests one of two approaches: Eliminate the word manage, but do not focus on encroachment and instead focus on outages. For instance: "Each Transmission Owner shall prevent vegetation related outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. Focus on the word "manage", similar to the existing FAC-003 standard, and move R3 to a new R1 to develop a management plan, and then the existing R1 and R2 become R2 an R3 and require execution of that plan in the words of R7, which would in turn enables elimination of R7.

Response: The SDT thanks you for your comments. In Order 693, FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines

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how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.				
Richard J. Padilla	Pacific Gas and Electric Company	5	Affirmative	There needs to be a change in the footnotes 2 and 4 to remove the exemption for “arboricultural activities or horticultural or agricultural activities” and replace it with the term “ installation of"
Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.				
Wayne Lewis	Progress Energy Carolinas	5	Affirmative	There needs to be a change in the footnote 2 and footnote 4 to remove the exemption for “arboricultural activities or horticultural or agricultural activities” and replace it with the term “installation of.
Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.				
Liam Noailles	Xcel Energy, Inc.	5	Affirmative	Xcel Energy still believes the requirement in R6 that mandates an annual inspection is an ineffective approach and may actually go against the Commission’s determination in FERC Order No. 693. The drafting team’s response to our last round of comments on this issue was that “...the SDT was directed by Order 693 to set a minimum inspection criteria”. It is clear in Order 693 that the Commission is not satisfied with allowing entities to choose their own inspection cycles, as the standard currently allows. However, we fail to see where the Commission mandated a minimum inspection cycle to be uniformly applied continent-wide. We urge the drafting team to revisit paragraphs 719 through 721 of Order 693. According to paragraph 721, the Commission recognizes that unique intervals by region, “based on local factors”, are reasonable and appropriate. By use of the plural term “cycles”, FERC anticipates the resolution may include multiple inspection

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				cycles. Furthermore, in paragraph 719, FERC acknowledges that a minimum inspection cycle may not be the only way to address their concern. In fact, mandating an annual inspection cycle may actually go against the Commission's guidance in paragraph 720. Here is an excerpt: "...the Commission is dissuaded from requiring the ERO to create a backstop inspection cycle at this time. Instead, the Commission agrees that an entity's vegetation management program should be tailored to anticipated growth in the region and take into account other environmental factors. The goal is to assure that transmission owners conduct inspections at reasonable intervals." As an alternative, we propose a mid-cycle inspection. A mid-cycle inspection is based on an interval that is justified with data and technical expertise. A mid-cycle inspection would still require entities to conduct inspections at a specified interval, while allowing for differences based upon "physical and geographic factors". Not only would this approach fully address the Commissions concerns, but it would take into account the interests of stakeholders, landowners and rate-payers. We recognize that a mid-cycle inspection interval is not as easy to audit as an annual requirement, but it is a far more practical and cost-effective approach that, when applied based on an entity's expertise with its own facilities, ensures reliability.
Response: The SDT thanks you for your comments. The SDT recognizes that a number of Transmission Owners in North America may prefer to set their own inspection intervals. The SDT can also see attractiveness for a mid-cycle inspection concept; however, this introduces new complexities in planning, documentation and auditing. Because there is substantial industry support for an annual inspection interval , the SDT believes that the industry is best served with this approach.				

Voter	Entity	Segment	Vote	Comment
Edward P. Cox	AEP Marketing	6	Affirmative	American Electric Power believes that the phrase "arboricultural activities or horticultural or agricultural activities" was mistakenly introduced into Footnotes 2 and 4, and should be deleted from both footnotes. If the phrase remains in the Standard, it may empower orchard growers, landowners and others to plant trees on the right of way and challenge Transmission Owners' rights to perform maintenance on the presumption that the standard will exempt the TO from violating the outage or encroachment requirements. For increased clarity, AEP offers the following change to the second paragraph of M1, as well as the second paragraph of M2. The original text “If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation” should be replaced with “If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation growing into or blowing together with the conductor within the ROW, this shall be considered the equivalent of a Real-time observation. A brief encroachment caused by falling vegetation passing through the MVCD is not considered an encroachment in this requirement”.
Response: Thanks you for your comments. The SDT made the suggested changes to the footnotes. Regarding the issue of fall-ins, the SDT is sympathetic to your concern. In fact, the SDT had originally crafted language similar to that which you suggested. However, due to concerns expressed by regulators and others, the exemption for encroachment violations due to falling vegetation from inside the right of way was removed.				

Voter	Entity	Segment	Vote	Comment
Brenda S. Anderson	Bonneville Power Administration	6	Affirmative	BPA Comments with Yes Vote: In R1 and R2 and their associated VSLs, the SDT added the phrase “in order of increasing severity” and added the sentence, “The types of encroachments are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO’s vegetation maintenance program.” to the Rationale boxes for R1/R2. Do you agree? If answer is no, please explain. BPA prefers the stratified levels of violation severity presented in the table for R1 and R2. Foot note # 2 on page 8 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. Foot note # 4 on page 12 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. In response to comments received that requirement R3 is unclear with respect to intent, the SDT added “maintenance strategies.” Do you agree this clarifies the intent? If answer is no, please offer alternative language. The TO procedures / policies and specifications shall demonstrate the TO’s ability to manage the system at all rated conditions to maintain reliability. BPA believes that the intent is clear, but the fundamental approach of using the MVCD (table 2) to manage a vegetation program is still problematic. These values are

Voter	Entity	Segment	Vote	Comment
				flashover distances and are way too close. This is acknowledged in a footnote to table 2 but no identification of allowable buffers/distances between energized phase conductors at rated temperatures and vegetation is discussed (this is left up the transmission owners). Clarity is needed on this topic. Setting a finite distance limit based on recognized standards, good science and risk avoidance should be done for the industry. BPA has previously made this comment during the drafting of the standard. It was not addressed then, nor has it been addressed now.
Response: The SDT thanks you for your comments. The footnotes were changed to conform with your suggestions. With respect to comments about the MVCD, R3 does not suggest the MVCD be used as a distance to manage vegetation. The MVCD was established as a beginning of a series of "building blocks" for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions. R3 requires that a Transmission Owner consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this "building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD distances. In a performance based standard, requirements are focused on "what" needs to be accomplished to achieve desired results and avoids prescriptive requirements of "how" to achieve that result. TO's are in the best position to determine the appropriate management approach suited for their system rather than a "one size fits all" or "fill in the blanks" requirements that could suppress best practices for vegetation management.				
Matthew D Cripps	Cleco Power LLC	6	Negative	Cleco disagrees with the SDT revising the definition for Right-of-Way (ROW). Right-of-Way is a term that has had a consistent meaning throughout history. If NERC tries to redefine the term, it will only add confusion because most entities will not reference the NERC glossary for a term which is widely used in the industry. In lieu of "Active Transmission Line ROW", please use another term such as Transmission Corridor. No assumptions would be made when reading in the Standard the the Entity is to maintain

Voter	Entity	Segment	Vote	Comment
				vegetation located within the Transmission Corridor. Since the term is not commonly used, the NERC glossary would be referenced. Also, Cleco disagrees that an encroachment into the MCVD that does not cause an outage should be considered non-compliant as stated in R1 and R2. The encroachment should only be reportable similar to misoperations as is in the PRC-004 standard.
Response: Thanks for your comments. The existing ROW definition in the glossary was created by and for the FAC-003-1 and was moved there when that standard was adopted. The definition includes a series of options that give the Transmission Owner latitude in establishing ROW width. It does not require selecting a single method for its system. The term blowout standard is not capitalized and is not a defined term. This phrase in the definition allows a Transmission Owner to use its internal engineering standards or the general engineering standards that were in effect when the line was constructed to determine the ROW width. The SDT has limited the definition of Right-of-Way to a corridor of land with a defined width to operate a transmission line. This does not include danger tree rights. The definition of the MVCD is now added to this Standard. While use of the pre-2007 records is a compliance issue and is not in the purview of the SDT, it is the intent of the language in the definition that you could use this information. Regarding your second comment (begins with Also,): the MVCD was established as a beginning of a series of "building blocks" for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions. R3 requires that a Transmission Owner consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this "building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD. Other related requirements of this "Defense in Depth" Standard serve to address any number of scenarios which may arise or hinder the TO's ability to always strictly adhere to the management approach(s) established within R3. Thus the other requirements of this Standard provide the latitude for appropriate actions to remedy the condition without penalty. Further, trees which have encroached inside the MVCD are evidence of a deficiency in vegetation maintenance.				
Nickesha P Carrol	Consolidated Edison Co. of	6	Affirmative	Reply to Question 5 on Comment Form: The added language for the annual work plan percentage complete calculation is

Voter	Entity	Segment	Vote	Comment
	New York			shown in R7 not M7 as stated in the question. In the Guideline and Technical Basis Section for Requirement R6, there is a sample calculation shown for the amount of lines the TO failed to inspect. An example should also be included for Requirement R7 since there is some confusion regarding how modifications to the work plan affect the calculation. In the Lower VSL column for R7, it states that the TO failed to complete up to 5% of its annual vegetation work plan (including modifications if any). If a TO operates 100 lines and submits a justified modification that affects 10 miles of lines, the total number of units in the final amended plan is 90 miles. When you read the VSL, it is somewhat confusing since the information in parenthesis says that the calculation 'includes' the modifications. Should it state 'excludes modifications if any' or the VSLs can simply be re-written to state that ..The TO failed to complete up to x% of the final amended plan.'
Response: The SDT thanks you for your comments. The percentage should be based on the plan as modified. The SDT has changed the language in the standard to reflect this more clearly.				
Mark S Travaglianti	FirstEnergy Solutions	6	Affirmative	FirstEnergy supports standard FAC-003-2 and would appreciate consideration of our comments submitted through the formal comment period.
Response: The SDT thanks you for your comments. Please see our consideration of your comments within the responses to the formal comments.				
Thomas E Washburn	Florida Municipal Power Pool	6	Negative	The concern is that entities may not be able prove compliance with the standard. R1 and R2 say that: "Each Transmission Owner shall manage vegetation to prevent encroachments ...". If the requirements were interpreted such that "manage" is the operative word, then, we are OK because we can provide evidence of managing a program,

Voter	Entity	Segment	Vote	Comment
				such as a vegetation management plan and evidence of executing that plan (which does not align with the Measures). However, that 1) would cause the standard to not be performance based, and 2) it would be duplicative of the other requirements of the standard. If the requirements were interpreted with "prevent encroachment" as the operative phrase (which would be an incorrect interpretation from the construct of the sentence) there is no way to provide sufficient evidence that encroachment was prevented during the audit-period. The suggested Measures are not sufficient evidence to prove compliance with that interpretation of the requirement. For instance, most encroachments do not result in outages; hence, lack of outages cannot prove that there were no encroachments, and real time observations are insufficient because it is a spot-check that does not cover the audit period. There are other weaknesses in the standard, such as R4 being un-measurable therefore unenforceable. However, in the guilty until proven innocent paradigm we live in, FMPA's primary concern is that industry could be put into a no-win situation of not being able to prove compliance with the standard if R1 and R2 are interpreted as "prevent encroachment", and if R1 and R2 are interpreted as "manage" then it is not a performance based standard as advertised. Performance based focused on preventing vegetation related outages. For instance: "Each Transmission Owner

Voter	Entity	Segment	Vote	Comment
				shall prevent vegetation related outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. Modify the standard to be similar to the currently mandatory non-results based standard and focus on the word "manage". This would essentially mean eliminating R1 and R2 since the rest of the standard focuses on having a plan and managing to that plan..
Response: The SDT thanks you for your comments. In Order 693, FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.				
Silvia P. Mitchell	Florida Power & Light Co.	6	Affirmative	1. The SDT proposes a revised NERC Glossary definition for Right-of-Way (ROW). This revised definition will be used in lieu of the Active Transmission Line ROW. Do you agree? If answer is no, please explain. Yes 2. In R1 and R2 and their associated VSLs, the SDT added the phrase "in order of increasing severity" and added the sentence "The types of encroachments are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO's vegetation maintenance program." to the Rationale boxes for R1/R2. Do you agree? If answer is no, please explain. Yes Although NextEra Energy Inc. (NextEra), including Florida Power & Light Company, agrees with the changes referenced for R1

Voter	Entity	Segment	Vote	Comment
				and R2, NextEra is concerned that the exemptions identified in footnote 2 for "...arboricultural activities or horticultural or agricultural activities...," and similar language in footnote 4, are too broad. For example, this language appears to include an exemption for a landowner, who, during arboricultural activities or horticultural or agricultural activities, causes a vegetation contact with a transmission line (e.g., cutting or lifting a tree into a transmission line). This places the Transmission Owner in the difficult position of a landowner arguing it is exempt from a controllable risk. Thus, the "...arboricultural activities or horticultural or agricultural activities..." references should be removed from footnote 2, and the similar language in footnote 4 3. In response to comments received regarding the term "investigation" in M1/M2, the SDT substituted "confirmation...by the Transmission Owner.." in its place, among other minor edits to these measures. Do you agree? If answer is no, please explain. Yes 4. In response to comments received that requirement R3 is unclear with respect to intent, the SDT added "maintenance strategies". Do you agree this clarifies the intent? If answer is no, please offer alternative language. Yes 5. The SDT added clarifying language in M7 to explain how the annual work plan percentage complete calculation is to be performed. Is this adequate? If no, please provide improved examples. Yes

Voter	Entity	Segment	Vote	Comment
Response: The SDT thanks you for your comments. The team has made the appropriate modifications to the footnotes as you suggested.				
Thomas Saitta	Kansas City Power & Light Co.	6	Negative	The Standard lacks clarity regarding the facilities that are subject to Requirement 7. It is important that a Standard be clear and not introduce ambiguity or confusion. There are several references throughout the Standard to "for all applicable lines" and it should be made clear the work plan is specific to "all applicable lines".
Response: The SDT thanks you for your comments. The phrase, "applicable lines" was added to R7 in support of your suggestion.				
Eric Ruskamp	Lincoln Electric System	6	Affirmative	While supportive of the drafting team's efforts, LES believes a change is warranted in Footnote 2 and Footnote 4 to remove the exemption for "arboricultural activities or horticultural or agricultural activities" and replace with the term "installation of". As currently drafted, the wording could potentially be construed to mean that the TO would or could be constrained or refused permission to prune and remove any and all vegetation in the ROW in accordance with the full legal rights of the ROW agreement(s).
Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.				
John T Sturgeon	Progress Energy	6	Affirmative	There needs to be a change in the footnote 2 and footnote 4 to remove the exemption for "arboricultural activities or horticultural or agricultural activities" and replace it with the term "installation of.
Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.				
David F. Lemmons	Xcel Energy, Inc.	6	Affirmative	Xcel Energy still believes the requirement in R6 that mandates an annual inspection is an ineffective approach and may actually go against the Commission's

Voter	Entity	Segment	Vote	Comment
				determination in FERC Order No. 693. The drafting team's response to our last round of comments on this issue was that "...the SDT was directed by Order 693 to set a minimum inspection criteria". It is clear in Order 693 that the Commission is not satisfied with allowing entities to choose their own inspection cycles, as the standard currently allows. However, we fail to see where the Commission mandated a minimum inspection cycle to be uniformly applied continent-wide. We urge the drafting team to revisit paragraphs 719 through 721 of Order 693. According to paragraph 721, the Commission recognizes that unique intervals by region, "based on local factors", are reasonable and appropriate. By use of the plural term "cycles", FERC anticipates the resolution may include multiple inspection cycles. Furthermore, in paragraph 719, FERC acknowledges that a minimum inspection cycle may not be the only way to address their concern. In fact, mandating an annual inspection cycle may actually go against the Commission's guidance in paragraph 720. Here is an excerpt: "...the Commission is dissuaded from requiring the ERO to create a backstop inspection cycle at this time. Instead, the Commission agrees that an entity's vegetation management program should be tailored to anticipated growth in the region and take into account other environmental factors. The goal is to assure that transmission owners conduct inspections at reasonable intervals." As an alternative, we propose a mid-cycle inspection. A mid-cycle inspection is based on an interval that is justified with data and technical expertise. A mid-cycle inspection would still require entities to conduct inspections at a specified interval, while allowing for differences based upon "physical

Voter	Entity	Segment	Vote	Comment
				and geographic factors". Not only would this approach fully address the Commissions concerns, but it would take into account the interests of stakeholders, landowners and rate-payers. We recognize that a mid-cycle inspection interval is not as easy to audit as an annual requirement, but it is a far more practical and cost-effective approach that, when applied based on an entity's expertise with its own facilities, ensures reliability.
Response The SDT thanks you for your comments. The SDT recognizes that a number of Transmission Owners in North America may prefer to set their own inspection intervals. The SDT can also see attractiveness for a mid-cycle inspection concept; however, this introduces new complexities in planning, documentation and auditing. Because there is substantial industry support for an annual inspection interval and due to the vastly simpler auditing associated with an annual interval, the SDT believes that the industry is best served with this approach.				
Jacquie Smith	ReliabilityFirst Corporation	10	Negative	ReliabilityFirst votes "No" on the proposed FAC-003-2 because ReliabilityFirst believes that the currently effective FAC-003-1, despite any weaknesses it may have, better ensures the reliability of the bulk electric system. First, under the proposed FAC-003-2, Requirements 1 and 2, the minimum clearances are reduced. Second, under the proposed structure of FAC-003-2, Requirements 1 and 2, violations would only occur where an encroachment of the Minimum Vegetation Clearance Distance ("MVCD") is observed in real time or after vegetation contact, i.e., after actual harm has occurred. Consequently, the proposed structure appears to convert a preventative maintenance standard into a standard that is essentially only violated after it is too late. The current structure from Version 1 of the standard (i.e., the Clearance

Voter	Entity	Segment	Vote	Comment
				1 and 2 requirements) better ensures reliability because they seek to ensure that registered entities discover problematic vegetation conditions prior to encroachments leading to flashover or vegetation contacts. For example, the current Clearance 1 is the "clearance distances to be achieved at the time of transmission vegetation management work." And the current Clearance 2 is the "specific radial clearances to be maintained under all rated electrical operating conditions." See FAC-003-1, R1.2.1 and R1.2.2 (emphasis added). Third, the draft standard appears to inappropriately and unnecessarily reduce the risk factor assigned to some failures to manage vegetation. It draws a distinction between those transmission lines that are elements of IROLs or Major Western Electricity Coordinating Council ("WECC") transfer paths and those that are not. This distinction is apparently based on the assumption that vegetation management violations on transmission lines that are not elements of IROLS or Major WECC transfer paths are less important. ReliabilityFirst disagrees with this assumption. Simply put, both are serious issues and the distinction is inappropriate and unnecessary. The Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, highlights the importance of all vegetation management work by identifying inadequate vegetation management as one of the causes of the 2003 Blackout. See Blackout Report, at p. 20. Finally, ReliabilityFirst disagrees with the proposed Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs")

Voter	Entity	Segment	Vote	Comment
				because they are premised on the same inappropriate and unnecessary distinction that vegetation management violations on transmission lines that are not elements of IROLS or Major WECC transfer paths are less important. For the foregoing reasons, ReliabilityFirst votes "No" on the proposed FAC-003-2.

Response: As with a Transmission Owner's determination of its Clearance 1 distances under version 1 of the Standard, Requirement 3 of the revised Standard begins with the MVCD distances (just as Clearance 1 began with IEEE-516 distances) and then requires additional consideration for conductor movement, vegetation growth variables, and the utility's maintenance approach. These are essentially the same considerations required by version 1 of the existing Standard when developing Clearance 1 distances. Therefore, nothing has been lost in the revised Standard.

The MVCD was established as a beginning of a series of "building blocks" for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions.

R3 requires that a Transmission Owner consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this "building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD distances.

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard. The draft, when taken in whole, does present a "preventative" maintenance standard.

The Standard has been designed utilizing a "Defense in Depth" strategy which provides for multiple layers of defense against a MVCD encroachment or an outage. These other layers of defense are identified in requirements R3 through R7. R3 through R7 are the same preventative maintenance requirements as contained in Version 1 of the Standards. Additionally, Measure 3 for R3 now tests the reasonableness and practicality of a TO's vegetation management approach long before field work is implemented; other requirements such as R7 require preventative maintenance work to be completed before encroachments occur.

The SDT asserts that different VRF's for IROL and non-IROL lines strengthens the reliability of the standard. Vegetation

Voter	Entity	Segment	Vote	Comment
managers that do not know which lines have IROLs or are designated as WECC Transfer Paths may be inappropriately limiting resources allocated to vegetation management for a line with an IROL or a line designated as a WECC Transfer Path. A vegetation manager must ensure that the lines with IROLs and lines designated as WECC transfer paths are absolutely clear. By correctly identifying the risk associated with lines with IROLs line and/or lines designated as WECC Transfer Paths, the standard helps to assure that appropriate resources are applied.				

Exhibit F

Analysis of how VRFs and VSLs Were Determined Using FERC Guidelines

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-07 Vegetation Management

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in FAC-003-2 Vegetation Management.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The SDT applied the following NERC criteria when developing these VRFs:

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report
The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF Justification

VRF for FAC-003-2, Requirements R1:

The SDT assigned this requirement a VRF of High.

- FERC's Guideline 2 — Consistency within a Reliability Standard. The Requirement states transmission owners must manage vegetation for lines that represent a significant risk of cascading, instability, or separation. The VRF is only applied at the Requirement level and each Requirement Part is treated equally.
- FERC's Guideline 3 — Consistency among Reliability Standards. The requirement mandates measurable performance with regard to vegetation management to ensure that the risk of cascading, separation, and instability is minimized. Other requirements with similar performance based outcomes that could lead to cascading, instability, or separation carry a High VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. IROLs and Major WECC Transfer Paths by definition have an increased potential for leading to cascading, separation, or instability. Therefore this requirement was assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. The requirement contains only one objective (to manage vegetation of lines that carry increased risk of instability, cascading, or separation) and only one VRF was assigned.

VRF for FAC-003-2, Requirements R2:

The SDT assigned this requirement a VRF of Medium.

- FERC's Guideline 2 — Consistency within a Reliability Standard. The Requirement states transmission owners must manage vegetation for lines that do not represent a significant risk of cascading, instability, or separation. The VRF is only applied at the Requirement level and each Requirement Part is treated equally.
- FERC's Guideline 3 — Consistency among Reliability Standards. The requirement mandates measurable performance with regard to vegetation management to ensure that the risk of equipment damage is minimized. Other requirements similar performance based outcomes that could lead to equipment damage carry a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Lines that are not IROLs and Major WECC Transfer Paths by definition have less potential for leading to cascading, separation, or instability. Therefore this requirement was assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. The requirement contains only one objective (to manage vegetation of lines that carry minimal risk instability, cascading, or separation) and only one VRF was assigned.

VRF for FAC-003-2, Requirements R3:

The SDT assigned this requirement a VRF of Lower.

- FERC's Guideline 2 — Consistency within a Reliability Standard. The Requirement mandates the Transmission Owner to have documented strategies, procedures, processes, or specifications. The VRF is only applied at the Requirement level and each Requirement Part is treated equally.
- FERC's Guideline 3 — Consistency among Reliability Standards. This requirement calls for an entity to have documented strategies, procedures, processes, or specifications. This requirement is administrative in nature, and is consistent with other standards requiring documentation.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have a document is not likely to directly affect the electrical state or the capability of the bulk electric system, or the

ability to effectively monitor and control the bulk electric system. Development of the documents is a requirement that is administrative in nature and is in a planning time frame that, if violated, would not, under emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.. Therefore this requirement was assigned a Lower VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. R2 contains only one objective which is to have documents(s). Since the requirement is to have a documents, only one VRF was assigned.

VRF for FAC-003-2, Requirements R4:

The SDT assigned this requirement a VRF of Medium.

- FERC's Guideline 2 — Consistency within a Reliability Standard. The Requirement specifies that transmission owners must report vegetation conditions that are likely to cause a Fault to the control center holding switching authority for the associated line. The VRFs are only applied at the Requirement level and there are no Requirement Parts for separate consideration.
- FERC's Guideline 3 — Consistency among Reliability Standards. The requirement mandates notifications that could hinder the ability to effectively monitor and control the bulk electric system. Other requirements that address with similar outcomes are also assigned Medium VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to report vegetation conditions may affect the ability to effectively monitor and control the bulk electric system Therefore this requirement was assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. The requirement contains only one objective (to report) , and only one VRF was assigned.

VRF for FAC-003-2, Requirements R5:

The SDT assigned this requirement a VRF of Medium.

- FERC's Guideline 2 — Consistency within a Reliability Standard. The Requirement mandates that a Transmission Owner, when constrained from performing vegetation work that may lead to a vegetation risk encroachment into the MVCD prior to the implementation of the next annual work plan, must take corrective action to ensure continued vegetation management to prevent encroachments. The VRF is only applied at the Requirement level and there are no Requirement Parts for separate consideration.
- FERC's Guideline 3 — Consistency among Reliability Standards. The requirement mandates corrective action that, if not taken, could directly affect the electrical state or the capability of the bulk electric system. Other requirements with similar outcomes are also assigned Medium VRFs.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to take corrective action could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. Therefore this requirement was assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. The requirement contains only one objective (to take corrective action), and only one VRF was assigned.

VRF for FAC-003-2, Requirements R6:

The SDT assigned this requirement a VRF of Medium.

- FERC's Guideline 2 — Consistency within a Reliability Standard. The Requirement specifies that the transmission owner must perform a Vegetation Inspection of 100% of its lines at least once per calendar year. The VRFs are only applied at the Requirement level and there are no Requirement Parts for separate consideration.
- FERC's Guideline 3 — Consistency among Reliability Standards. The requirement mandates inspections that, if not performed, could affect the ability to effectively monitor and control the bulk electric system. Other requirements with similar outcomes are also assigned Medium VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to perform an inspection could affect the ability to effectively monitor and control the bulk electric system. Therefore this requirement was assigned a lower VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. The requirement contains only one objective (to perform a Vegetation inspection), and only one VRF was assigned.

VRF for FAC-003-2, Requirements R7:

The SDT assigned this requirement a VRF of Medium.

- FERC's Guideline 2 — Consistency within a Reliability Standard. The Requirement specifies that the Transmission Owner must complete 100% of its annual vegetation work plan. The VRFs are only applied at the Requirement level and there are no Requirement Parts for separate consideration.
- FERC's Guideline 3 — Consistency among Reliability Standards. The requirement mandates completion of work that, if not completed, could affect the electrical state or the capability of the bulk electric system. Other requirements with similar outcomes are also assigned Medium VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to complete the annual vegetation work plan could affect the electrical state or the capability of the bulk electric system. Therefore this requirement was assigned a lower VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. The Requirement contains only one objective (to complete 100% of the annual vegetation work plan), and only one VRF was assigned.

Justification for Assignment of Violation Severity Levels

In developing the VSLs, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

> Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VSLs for FAC-003-2 Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations..	This is a new requirement, and accordingly cannot lower the current level of compliance.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for FAC-003-2 Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	This is a new requirement, and accordingly cannot lower the current level of compliance.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for FAC-003-3 Requirement R3

R#	Compliance with NERC's Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The previous standard graded the VSLs based on the completeness of the TVMP. The new VSL is structured similarly, but has omitted the "Low" level, effectively raising the minimum level of compliance.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for FAC-003-3 Requirement R4:

R#	Compliance with NERC's Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The previous standard does not require actual communication, while the new standard does. Accordingly, this should be treated as a new requirement, and therefore cannot lower the current level of compliance.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for FAC-003-3 Requirement R5:

R#	Compliance with NERC's Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - Severe: The performance or product measured does not substantively meet the intent of the requirement.	The only VSL is Severe, and therefore, the VSL cannot result in a lower level of compliance.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for FAC-003-3 Requirement R6:

R#	Compliance with NERC's Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The previous standard does not require actual inspections, while the new standard does. Accordingly, this should be treated as a new requirement, and therefore cannot lower the current level of compliance.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for FAC-003-3 Requirement R7:

R#	Compliance with NERC's Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The VSLs in the previous standard were focused on completeness of the document, with the "Severe" VSL only reserved for entities that did not have or implement their plan. The proposed VSLs are graded based on the amount of the plan completed, giving a clear indication that partial completion is still a violation, establishing a level of compliance in excess of what was established previously.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

Exhibit G

Record of Development of Proposed FAC-003-2 — Transmission Vegetation Management Reliability Standard

Project 2007-07
Transmission Vegetation Management

Related Files

Status:
Adopted by the Board of Trustees on November 3, 2011.

Purpose / Industry Need:
FAC-003-1 was approved in 2006. It has some 'fill-in-the-blank' components to eliminate. In addition, the following comments submitted by FERC and stakeholders need to be addressed in the refinement of the standard:

FERC Order 693 items
Address the issue regarding applicability:

- Work with the reliability entities and the ERO to collect and make available to the FERC, a list of critical lower voltage transmission lines. (Refer to Applicability 4.3 section of the standard.)
- Consider other criteria in determining applicability of the standard to sub 200kV lines.
- Address the issue of clearances for lines on both federal and non-federal lands:
- Review and analyze outage data (collected by the ERO) then consider defining clearances needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal and non-federal land.
- Consider revising the definition of right of way to encompass required clearance areas.
- Review the suitability of IEEE 516-2003 standard for minimum vegetation clearance.
- Review and analyze outage data (collected by the ERO) then consider defining clearances needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal and non-federal land.
- Consider revising the definition of right of way to encompass required clearance areas.
- Review the suitability of IEEE 516-2003 standard for minimum vegetation clearance.

Procedural items

- Re-format standard to bring it into conformance with the latest version of the Reliability Standard Development Procedure and the ERO Sanctions Guidelines.
- Remove references to RRO in the standard and substitute a responsible entity.
- Add newly developed compliance elements such as time horizons, violation risk factors, violation severity levels, etc.

Stakeholder items

- Prepare technical reference material such as a "white paper" to aid in understanding the technical basis for the standard.
- Review reporting criteria for Category 3 outages in the proposed technical reference material and may remove the reporting requirement of Category 3 outages in R.3 and R.4.
- Consider deleting requirement R.4.
- Review the reporting exemptions to include all category outages under major disasters in Requirement R3.2.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

Draft	Action	Dates	Results	Consideration of Comments
Draft 6 Standard FAC-003-2 Clean (73)| Redline to Last Posting(74) Implementation Plan Clean(75) | Redline(76) **Technical References:** Clean (77)| Redline to Last Posting(78) **Supporting Materials:** FAC-003-1(79) Mapping Table(80) New and Modified Definitions(81) Consideration of Issues and Directives(82) Violation Risk Factor & Violation Severity Level Assignment(83) Technical, Policy and Regulatory Issues Addressed by SDT(84)	Recirculation Ballot Info(85) Vote >>	10/04/11 - 10/13/11 (closed)	Summary(86) Full Record(87)	
Draft 5 Standard FAC-003-2 FAC-003-2 Clean (56)| Redline to Last Posting(57)	Successive Ballot Info(64) Vote >>	02/18/11 - 02/28/11	Full Record(66) Summary(67) Non-binding Results(68)	Consideration of Comments (70) Consideration of Comments: Non-Binding Poll (71)

Implementation Plan Clean(58) | Redline to Last Posting(59) **Supporting Materials:** FAC-003-1(60) Comment Form (Word)(61) **Technical White Paper** Clean (62)| Redline to Last Posting(63)	Comment Period Info(65) | Submit Comments>>	01/27/11 - 02/28/11	Comments Received(69)	Consideration of Comments (72)
Draft 4 Standard – FAC-003-2 FAC-003-2 Clean (41)| Redline to Last Posting(42) Implementation Plan Clean(43) | Redline to Last Posting(44) **Supporting Materials:** Comment Form (Word)(45) Mapping Document(46) Technical White Paper(47)	Initial Ballot Vote>> | Info(48)	07/09/10 - 07/19/10 (closed)	Full Record(51) Summary(52)	Consideration of Comments(54)
	Pre-ballot Review Join>> | Info(49)	06/17/10 - 07/07/10 (closed)		
	Comment Period Info(50) | Submit Comments >>	06/17/10 - 07/17/10 (closed)	Comments Received(53)	Consideration of Comments (55)
Draft 3 Standard – FAC-003-2 FAC-003-2(33) Implementation Plan(34) Mapping Document(35) **Supporting Materials:** Comment Form (Word)(36) Technical Reference Document(37)	Informal Comment Period Info(38) | Submit Comments>>	03/01/10 - 03/31/10 (closed)	Comments Received(39)	Consideration of Comments (40)

Draft 2 Standard – FAC-003-2 FAC-003-2 Clean (24)| Redline to Last Posting(25) Mapping Document(26) **Supporting Materials:** Comment Form (Word)(27) FAC-003-2 Technical White Paper(28) Implementation Plan(29)	Comment Period Info(30) | Submit Comments>>	09/10/09 - 10/24/09 (closed)	Comments Received(31)	Summaries (32)
Draft 1 Standard – FAC-003-2 FAC-003-2(17) Mapping Changes(18) **Supporting Materials:** Comment Form (Word)(19) FAC-003-2 – Technical White Paper(20)	Comment Period Info(21) | Submit Comments>>	10/27/08 – 11/25/08 (closed)	Comments Received(22)	Consideration of Comments(23)
Draft SAR Version 3 Vegetation Management Draft SAR Version 2(13) Draft SAR Version 3 Clean (14)| Redline to 1st Posting(15)	Standard Drafting Team Nomination Submit Nomination(16)	07/03/07 - 07/17/07 (closed)		
Draft SAR Version 2	Comment Period	04/10/07 -	Comments Received(11)	Consideration of

Vegetation Management Draft SAR Version 2(7) Redline to 1st Posting(8)	Info(9)> | Submit Comments(10)	05/09/07 (closed)		Comments(12)
	SAR Drafting Team Nominations Submit Nomination(6)	01/29/07 (closed)		
Draft SAR Version 1 Vegetation Management Draft SAR Version 1(1)	Comment Period Info(2) |Submit Comments(3)	01/15/07 - 02/14/07 (closed)	Comments Received(4)	Consideration of Comments (5)

Standard Authorization Request Form

Title of Proposed Standard Project 2007-07	Revisions to FAC-003-1 Vegetation Management Program
Request Date	January 9, 2007

SAR Requestor Information	**SAR Type** (*Check a box for each one that applies.*)	
Name Richard Schneider (To be replaced by SAR DT Chair when the SAR DT is appointed.)	☐	New Standard
Primary Contact Richard Schneider	☒	Revision to existing Standard
Telephone 609-452-8060 Fax	☐	Withdrawal of existing Standard
E-mail Richard.schneider@nerc.net	☐	Urgent Action

Purpose / Industry Need (Describe the purpose of the standard — what the standard will achieve in support of reliability.)

The purpose of revising this standard is to:

1. Provide an adequate level of reliability for the North American bulk power systems - the standard is complete and the requirements are set at an appropriate level to ensure reliability.
2. Ensure it is enforceable as a mandatory reliability standard with financial penalties - the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities, is clearly defined; the purpose, requirements, and measures are results-focused and unambiguous; the consequences of violating the requirements are clear.
3. Incorporate other general improvements described in the attached Standard Review Guidelines
4. Consider comments received from ERO regulatory authorities and stakeholders, as noted in the attached review sheets.
5. Satisfy the standards procedure requirement for five-year review of the standards.

Brief Description

This is a new standard that was approved in 2006. It has some 'fill-in-the-blank' components to eliminate. In addition, the following comments submitted by FERC and stakeholders need to be addressed in the refinement of the standard:

FERC NOPR

- Develop a minimum vegetation inspection cycle that allows variation for physical differences, as discussed above; and
- Remove the applicability to transmission lines operated at 200 kV and above so that the Reliability Standard applies to Bulk-Power System transmission lines that have an impact of reliability as determined by the ERO.

FERC staff report

- Objections to use of IEEE standard

Stakeholder Comments

- RA vs. RRO
- Too weak on compliance
- Format inconsistencies

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Reliability Coordinator	Ensures the reliability of the bulk transmission system within its Reliability Coordinator area. This is the highest reliability authority.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time.
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules.
☐	Planning Authority	Plans the Bulk Electric System.
☐	Resource Planner	Develops a long-term (>one year) plan for the resource adequacy of specific loads within a Planning Authority area.
☐	Transmission Planner	Develops a long-term (>one year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
☐	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
☒	Transmission Owner	Owns transmission facilities.
☐	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders.
☐	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer.
☐	Generator Owner	Owns and maintains generation unit(s).
☐	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
☐	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity, and all necessary Interconnected Operations Services as required.
☐	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.
☐	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☐	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all the following Market Interface Principles? *(Select "yes" or "no" from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Regional Differences

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Standard Review Guidelines

Applicability

Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose

Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements

Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability

Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations

Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness

Is this reliability standard complete and self contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance
In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?

Clear Language
Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality
Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements
In general, requirements for entities to have "capabilities" (this would include facilities for communication, agreements with other entities, etc.) should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to "maintain" their capabilities.

Consistent Terminology
To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a "unique" definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the "verb list" from the Drafting Team Guidelines? If not, do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk power system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system. A requirement that is administrative in nature;

or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Mitigation Time Horizon
The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the time frame of a day, but not real time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk power system.
- **Operations Assessment** — follow-up evaluations and reporting of real-time operations.

Violation Severity Levels
The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. (“Violation severity levels” replace existing “levels of non-compliance.”) The violation severity levels may be applied for each requirement or combined to cover multiple requirements, as long as it is clear which requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
- **Moderate: mostly compliant with significant exceptions** — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.

- **High: marginal performance or results** — The responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.
- **Severe: poor performance or results** — The responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

Compliance Monitor
Replace "Regional Reliability Organization" with "Electric Reliability Organization"

Fill-in-the-blank Requirements
Do not include any "fill-in-the-blank" requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard — then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in underfrequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization
Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates
Must be 1st day of 1st quarter after entities are expected to be compliant — must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC, and Regional Entities must be provided in the implementation plan.

Associated Documents
If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, "Associated Documents."

Functional Model Version 3
Review the requirements against the latest descriptions of the responsibilities and tasks assigned to functional entities as provided in pages 13 through 53 of the draft Functional Model Version 3.

Maureen E. Long
Standards Process Manager

January 15, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: Comment Periods Open for SAR to Modify Vegetation Management, SAR for Reliability Coordination and SAR and Standard to Modify Facility Ratings Standards

The Standards Committee (SC) announces the following standards actions:

SAR to Modify the Vegetation Management Standard FAC-003-1 Posted for 30-day Comment Period January 15–February 14, 2007

The SAR for Project 2007-07 proposes modifying the Vegetation Management standard FAC-003-1 to address concerns raised by FERC and stakeholders and to bring the standard into conformance with the ERO Rules of Procedure and the latest version of the *Reliability Standards Development Procedure.* Please use the comment form to provide comments on this SAR.

SAR to Modify the Reliability Coordinator Standards Posted for 30-day Comment Period January 15–February 14, 2007

The SAR for Project 2006-06 proposes retiring, modifying, or adding to existing requirements for the reliability coordinator to ensure that the complete set of requirements addresses all the processes, procedures, plans, tools, and authorities the reliability coordinator needs to support the reliable operation of the interconnected bulk power systems. This project involves addressing concerns raised by FERC and stakeholders and also involves bringing the set of standards into conformance with the ERO Rules of Procedure and the latest version of the *Reliability Standards Development Procedure.* Please use the comment form to provide comments on this SAR.

SAR and Standard to Modify the Facility Ratings Standards Posted for 45-day Comment Period January 15–February 28, 2007

The SAR for Project 2006-09 proposes modifying two Facility Ratings standards, FAC-008-1 and FAC-009-1, to address concerns raised by FERC and stakeholders and to bring the standard into conformance with the ERO Rules of Procedure and the latest version of the *Reliability Standards Development Procedure.* Because there were relatively few technical changes recommended for this set of standards, the revised standard, which combines FAC-008-1 and FAC-009-1, is posted for comment along with an implementation plan. Please use the comment form to provide comments on this SAR, standard and implementation plan.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Comment Form — 1st Posting of SAR for Revisions to Vegetation Management FAC-003-1

Please use this form to submit comments on the Vegetation Management SAR. Comments must be submitted by **February 14, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Vegetation Management" in the subject line. If you have questions, please contact Richard Schneider at richard.schneider@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs,
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations, Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

FAC-003-1 is a relatively new standard that was approved in 2006. FAC-003 has some "fill-in-the-blank" components to eliminate. In addition, the following comments submitted by FERC and stakeholders need to be addressed in the refinement of the standard:

FERC NOPR

- Develop a minimum vegetation inspection cycle that allows variation for physical differences, as discussed above; and
- Remove the applicability to transmission lines operated at 200 kV and above so that the Reliability Standard applies to bulk power system transmission lines that have an impact of reliability as determined by the ERO.

FERC staff report

- Objections to use of IEEE standard

Stakeholder Comments

- Reliability Coordinator vs. Regional Reliability Organization
- Too weak on compliance
- Format inconsistencies

The improvements to the standard should bring the standard's format and elements into conformance with the latest version of the *Reliability Standards Development Procedure* and the ERO Rules of Procedure.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☐ Yes

   ☐ No

   Comments:

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☐ Yes

   ☐ No

   Comments:

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

   ☐ Yes

   ☐ No

   Comments:

Please use this form to submit comments on the Vegetation Management SAR. Comments must be submitted by **February 14, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Vegetation Management" in the subject line. If you have questions, please contact Richard Schneider at richard.schneider@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	William J. Smith	
Organization:	Allegheny Power	
Telephone:	(724) 838-6552	
E-mail:	wsmith1@alleghenypower.com	

NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs,
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
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	☐	10 — Regional Reliability Organizations, Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

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FERC NOPR

- Develop a minimum vegetation inspection cycle that allows variation for physical differences, as discussed above; and
- Remove the applicability to transmission lines operated at 200 kV and above so that the Reliability Standard applies to bulk power system transmission lines that have an impact of reliability as determined by the ERO.

FERC staff report

- Objections to use of IEEE standard

Stakeholder Comments

- Reliability Coordinator vs. Regional Reliability Organization
- Too weak on compliance
- Format inconsistencies

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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☒ Yes
   ☐ No
   Comments:

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☒ Yes
   ☐ No
   Comments:

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

   ☐ Yes
   ☒ No
   Comments:

Please use this form to submit comments on the Vegetation Management SAR. Comments must be submitted by **February 14, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Vegetation Management" in the subject line. If you have questions, please contact Richard Schneider at richard.schneider@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Michael Johnson	
Organization:	Bonneville Power Administration	
Telephone:	360.418.2161	
E-mail:	mdjohnson1@bpa.gov	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs,
☐ **MRO**	☐	3 — Load-serving Entities
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	☐	10 — Regional Reliability Organizations, Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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FERC NOPR

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- Remove the applicability to transmission lines operated at 200 kV and above so that the Reliability Standard applies to bulk power system transmission lines that have an impact of reliability as determined by the ERO.

FERC staff report

- Objections to use of IEEE standard

Stakeholder Comments

- Reliability Coordinator vs. Regional Reliability Organization
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- Format inconsistencies

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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: Ok, Yes and No. The first FERC NOPR bullet needs to be addressed. The second bullet is clearly discribed in the standard. A. 4.4.3. The reader must read the statement in context. It meets the Standard Review Guidelines.

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments: Since this posting is for comment it would have been nice to provide more information as to why the FERC staff objects to the IEEE standard (since it meet the guidelines for as a North America standard. Also, why are stakeholder concerned with Reliability Coordinators vs. RRO?

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

   ☒ Yes

   ☐ No

   Comments: It is not clear if categroy 1 and 2 refer only to occupied ROW, or also to unoccupied area reserved by the Transmission Owner for future expansion.

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Individual Commenter Information		
(Complete this page for comments from one organization or individual.)		
Name:	William T. Rees	
Organization:	Baltimore Gas and electric	
Telephone:	410-291-3479	
E-mail:	William.T.Rees@bge.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs,
☐ **MRO**	☐	3 — Load-serving Entities
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	☐	10 — Regional Reliability Organizations, Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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- Remove the applicability to transmission lines operated at 200 kV and above so that the Reliability Standard applies to bulk power system transmission lines that have an impact of reliability as determined by the ERO.

FERC staff report

- Objections to use of IEEE standard

Stakeholder Comments

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- Too weak on compliance
- Format inconsistencies

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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: The revisions listed in the NOPR and FERC Staff Report do not provide the necessary justification to alter the requirements in the current FAC-003-1 document. The existing requirements already allow for each utility to specify the inspection requirements. There is no need to more prescriptive. The existing requirements already allow for the ERO to designate critical lines less than 200 kV so removal of the 200 kV benchmark is unecessary. The IEEE Standard is worthwhile to keep as a benchmark without which there would be no solid guidance for minimum clearances.

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: As noted above.

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

   ☐ Yes

   ☒ No

   Comments:

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Brian D. Bartos	
Organization:	Bandera Electric Cooperative, Inc.	
Telephone:	830-796-6074	
E-mail:	b.bartos@banderaelectric.com	
NERC Region		**Registered Ballot Body Segment**
☒ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs,
☐ **MRO**	☐	3 — Load-serving Entities
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

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FERC NOPR

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FERC staff report

- Objections to use of IEEE standard

Stakeholder Comments

- Reliability Coordinator vs. Regional Reliability Organization
- Too weak on compliance
- Format inconsistencies

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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: The items listed as potential revisions are vague and do not provide sufficient justification to alter the current requirements of this standard which has been in effect less than 1 year. The current standard allows for the region to determine which transmission lines are critical to reliability and should be included in a Transmission Owner's Transmission Vegetation Management Plan regardless of voltage classification. The current standard also allows each TO the flexibility to develop its plan in accordance with its specific geography and operating environment. There is no need to be more prescriptive.

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☒ Yes

   ☒ No

   Comments: As submitted, the SAR appears to completely re-open this standard negating many months of work and industry comment to reach the consensus reflected in the current FAC-003.

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

   ☐ Yes

   ☒ No

   Comments: See Comment #2

Comment Form — 1st Posting of SAR for Revisions to Vegetation Management FAC-003-1

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name: David Kiguel		
Organization: Hydro One Networks Inc.		
Telephone: 416-345-5313		
E-mail: David.Kiguel@HydroOne.com		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs,
☐ **MRO**	☐	3 — Load-serving Entities
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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations, Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: Hydro One Networks Inc.

Lead Contact: **David Kiguel**

Contact Organization: **Hydro One Networks Inc.**

Contact Segment: **1**

Contact Telephone: **416-345-5313**

Contact E-mail: **David.Kiguel@HydroOne.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
George Juhn	**Hydro One Networks Inc.**	**NPCC**	1

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

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FERC NOPR

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FERC staff report

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Stakeholder Comments

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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

☐ Yes

☒ No

Comments: We believe that at this time it is premature to move forward with changes to the standard that are based on voltage class issues. The Standard, as developed, applies to the BES which have been determined by a performance based methodology. NERC should wait until the BES vs. BPS issue is resolved.

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

☐ Yes

☒ No

Comments: To address FERC's objection to use the IEEE standard, it is necessary to clarify the objective of the Vegetation Management Standard. As we understand it, the focus of the FAC-003-1 standard is system reliability and as such, the responsibility and authority on defining and applying the safety margins is rightly assigned to the transmission owner. We request clarification on how employing safety factors will address reliability and how prescribing minimum clearances within the standard will improve reliability.

Please note that the Canadian Standards Association is revising standard C22.3 No. 1 - Overhead Systems. The new version will include clearances to vegetation and the proposed minimum clearances are in alignment with FAC-003-1.

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

☐ Yes

☒ No

Comments:

Please use this form to submit comments on the Vegetation Management SAR. Comments must be submitted by **February 14, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Vegetation Management" in the subject line. If you have questions, please contact Richard Schneider at richard.schneider@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
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	☒	10 — Regional Reliability Organizations, Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: NPCC, CP9 Reliability Standards Working Group

Lead Contact: Guy V. Zito

Contact Organization: NPCC

Contact Segment: 10

Contact Telephone: 212-840-1070

Contact E-mail: gzito@npcc.org

Additional Member Name	Additional Member Organization	Region*	Segment*
Ralph Rufrano	New York Power Authority	NPCC	1
Ed Thompson	Con Ed	NPCC	1
Jerad Barnhart	NSTAR	NPCC	1
Roger Champagne	Hydro Quebec TransEnergie	NPCC	1
Herb Schrayshuen	National Grid US	NPCC	1
Greg Campoli	New York ISO	NPCC	2
Kathleen Goodman	ISO-New England	NPCC	2
Bill Shemley	ISO-New England	NPCC	2
Ron Falsetti	The IESO, Ontario	NPCC	2
David Kiguel	Hydro One Networks Inc.	NPCC	1
Don Nelson	MA Dept of Tele. and Energy	NPCC	9
Murale Gopinathan	Northeast Utilities	NPCC	1
Guy Zito	NPCC	NPCC	10
Brian Hogue	NPCC	NPCC	10

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

FAC-003-1 is a relatively new standard that was approved in 2006. FAC-003 has some "fill-in-the-blank" components to eliminate. In addition, the following comments submitted by FERC and stakeholders need to be addressed in the refinement of the standard:

FERC NOPR

- Develop a minimum vegetation inspection cycle that allows variation for physical differences, as discussed above; and
- Remove the applicability to transmission lines operated at 200 kV and above so that the Reliability Standard applies to bulk power system transmission lines that have an impact of reliability as determined by the ERO.

FERC staff report

- Objections to use of IEEE standard

Stakeholder Comments

- Reliability Coordinator vs. Regional Reliability Organization
- Too weak on compliance
- Format inconsistencies

The improvements to the standard should bring the standard's format and elements into conformance with the latest version of the *Reliability Standards Development Procedure* and the ERO Rules of Procedure.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: NPCC participating members believe that it is premature to move forward with changes based on voltage class. Applicability of the standard should only be to those portions of the system that are part of the Bulk Power System which have been determined by a performance based methodology.

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: See response to question 1, above.

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

   ☒ Yes

   ☐ No

   Comments: Only if the Bulk Power System is determined as an impact based performance based methodology.

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Jimmy Etheridge	
Organization:	Georgia Transmission Corporation	
Telephone:	770-270-7650	
E-mail:	jimmy.etheridge@gatrans.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs,
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations, Regional Entities

Group Comments (Complete this page if comments are from a group.)			
Group Name:	SERC Vegetation Management Subcommittee		
Lead Contact:	**Richard Dearman**		
Contact Organization:	**TVA**		
Contact Segment:	**1**		
Contact Telephone:	**256-519-2067**		
Contact E-mail:	**redearman@tva.gov**		

Additional Member Name	Additional Member Organization	Region*	Segment*
Jay Farrington	**Alabama Electric Coop**	**SERC**	1
Randy Gann	**Alabama Power Co.**	**SERC**	1
Raymond Wiesehan	**Ameren**	**SERC**	1
John Neagle	**Associated Electric Coop**	**SERC**	1
Billy George	**Duke Energy Carolinas**	**SERC**	1
Ralph Hale	**Entergy**	**SERC**	1
Marc Tunstall	**Fayetteville PWC**	**SERC**	1
Jack Gardner	**Progress Energy Carolinas**	**SERC**	1
Jerry Lindler	**SCE&G**	**SERC**	1

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

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1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: The SERC VMS is unsure how to answer the question as it is worded, but has the following comments on the SAR:

   The current standard contains appropriate requirements and measures to ensure the owners vegetation management program is implemented and managed to ensure the reliability of the transmission system. Mandating inspection cycle frequencies will not enhance nor ensure reliability by inspecting more or less frequently. The minimum vegetation clearances at maximum operating conditions that are established within the owner's program, which is auditable by the ERO, will ensure reliability. Extending the requirements to lines other than those >200KV may reduce the focus on those lines and may cause the allocation of resources away from lines >200KV. Generally easements are narrower on lower voltage lines, requiring more resources and emphasis on these lines. This may have an effect on the ability to focus clearing efforts on those lines that will have a much greater impact on the bulk power system. The IEEE standard when used as the minimum clearance distance at maximum operating condition will ensure reliability when these clearances are maintained by vegetation management activities. In addition, we do not agree that a standard of zero tolerance for vegetaion-related outages in the ROW is weak on compliance.

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☐ Yes

   ☐ No

   Comments: Minimum Inspection Intervals:
   The SERC VMS believes that FAC 003-1 provides the proper amount of flexibility regarding vegetation inspection cycles and that the Standards Drafting Team should not impose minimum inspection intervals on a continent with such regional diversity in climate and plant life.

   The purpose of Requirement 1.1 of standard FAC-003-1 is to put the responsibility for proper inspection cycles on the entity that knows the local conditions and can best define what that inspection frequency should be, the Transmission Owner. Both NERC and the FERC staff have recognized that various local conditions can have an affect on the determination of adequate inspection frequencies. Establishing a mandatory minimum inspection frequency could have two detrimental effects on the industry.

   First, where a particular region is heavily forested and has heavy rainfall along with extended or year round growing seasons, a "back stop" minimum inspection frequency could lead transmission owners to conduct inspections less frequently than required by the local conditions. This could result in a Transmission Owner complying with the standard while not adequately protecting the reliability of that region's transmission system. This is a "lowest common denominator" approach which FERC has repeatedly stated is inappropriate for the reliability standards.

Second, where a particular region is arid, sparsely forested or has a minimum growing season, a "back stop" minimum could require a more frequent interval than is realistically needed. This would result in increased and unnecessary costs for electric utility customers without providing an increase in system reliability.

In its discussion of inspection intervals, FERC indicates that a "one-year vegetation inspection cycle is reasonable." FERC NOPR, 10/20/2002 paragraph 383. The Commission continues by stating "a one-year inspection cycle is the 'norm' for the industry, but not the lowest common denominator…" It follows from this observation that the industry as a whole recognizes and follows appropriate inspection intervals without a need to change the standard. Further, FERC also states "some variation to a continent-wide, one-year minimum inspection cycle should be allowed due to physical differences such as climate and species of vegetation." FERC NOPR 10/20/2006, paragraph 382. FERC's express recognition that a "one size fits all" approach is not appropriate further supports the SERC VMS's contention that the existing inspection requirements in standard FAC-003-1 should remain unchanged.

Finally, the performance metrics of FAC-003 require the reporting of applicable transmission interruptions that are caused by vegetation. This process should appropriately identify Transmission Owners' inspection cycles that are not adequate. In this event, the ERO has the authority to engage the Transmission Owner in enforcement compliance actions and, therefore, can remedy any vegetation-related outage that is attributed to the Transmission Owner's inspection frequency.

Standard Applicability:
The SERC VMS disagrees with the proposal to revise the 200 kV threshold for determining facilities subject to this standard.

The majority of transmission facilities below 200 kV have significantly different design/construction/operating characteristics and have not been cited as impacting bulk power system reliability. For example, the Final Report on the August 14, 2003 Blackout in the United states and Canada: Causes and Recommendations April 2004 by the U.S.-Canada Power System Outage Task Force and all referenced major blackouts(pages 103-115) in that report, cited only outages which involved vegetation at line voltages above 200 kV. Generally applying requirements appropriate for 200 kV lines to lines less than 200 kV will result in significant documentation and reporting of items such as restrictions, mitigation plans, off right-of-way vegetation-related outage investigation/information and other issues, all of which dilutes the focus on lines that directly impact bulk power system reliability.

Revising the standard to use general criteria or broad language for defining "Bulk Power System" transmission lines covered by the standard could become a "one size fits all" approach. If that approach were taken, the standard would cover a significant number of transmission lines that have no direct impact on bulk power system reliability under standard planning/operating conditions, resulting in a significant increase in costs for electric customers without improving "Bulk Power System" system reliability. The SERC VMS believes that the applicability provision of the standard should instead focus attention of the standard only on the transmission lines below 200 kV that directly impact "Bulk Power System" reliability, as the current version requires.

In sum, while the SERC VMS recognizes some validity in the Commission's concern, the SERC VMS recommends that the applicability provision of this standard should be revised only if existing system design, planning or operating reliability criteria and parameters are considered as a basis for defining the applicability of the standard. To that end, the SERC VMS recommends each Regional Entity (RE) determine applicability of FAC-003 to those lines within the region that are between 100 kV and 200 KV if and only if they are identified as operationally significant elements of Interconnection Reliability Operating Limits ("IROLs").

IEEE Standard for Minimum Clearances:
The SERC VMS disagrees with objections in the FERC staff report to the use of the IEEE 516-2003 clearance as the minimum acceptable distances for "Clearance 2". The IEEE 516-2003 tables are appropriate for defining the minimum acceptable clearances to prevent flashover between conductors and vegetation under all rated electrical operating conditions. Closer minimum clearances such as the minimum length of a support insulator could have been adopted as a "lowest common denominator" clearance. However the clearance in IEEE 516-2003 was adopted to ensure an additional margin of reliability. FERC staff references ANSI Z-133 which is a safety standard that addresses worker safety as well as the safety of the general public. As such, the purpose of ANSI Z-133 is to address worker safety and is not focused on transmission line reliability, which is the purpose of FAC-003-1. OSHA, NESC and other related safety standards have clearances in excess of IEEE 516-2003. Those clearances are clearly focused on safety issues and will still apply to other aspects of design and operation of electric facilities (such as public and worker safety) but do not need to be referenced in a vegetation management reliability standard.

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

☒ Yes

☐ No

Comments: Standard Applicability:
The outage reporting requirement for the RRO should be deleted. Making FAC-003 applicable to the RRO is in violation of the legislation that established the ERO. This legislation states that enforceable standards can apply only to owners, users and operators of the bulk power system. Futher, in the NOPR on NERC standards, FERC declined to approve those standards that applied to the RROs, in part because the RROs are not owners, users or operators.

Compliance:
The SERC VMS recommends deleting reporting requirements for Category 3 outages. These outages are not controllable, not relevant to compliance, not related to grid reliability, not related to cascading blackouts, and such reporting leads to unnecessarily biasing reliability related information.

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Individual Commenter Information

(Complete this page for comments from one organization or individual.)

Name:	John Loftis
Organization:	Dominion - Electric Transmission
Telephone:	(804) 819-2337
E-mail:	john.loftis@dom.com

NERC Region		Registered Ballot Body Segment
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs,
☐ **MRO**	☐	3 — Load-serving Entities
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	☐	10 — Regional Reliability Organizations, Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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FERC staff report

- Objections to use of IEEE standard

Stakeholder Comments

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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: We disagree with the proposal from FERC NOPR regarding removing applicability to transmission lines >200kv. The proposal to apply the Standard to lines the ERO deems to have an impact on reliability can create inconsistency between regions and is a "fill in the blank" requirement. It is not clear whether the proposed change would increase or decrease the number of transmission lines which are subject to reportable outages. In addition, we support the Standard's existing language that limits reporting to locked out lines only.

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

   ☐ Yes

   ☒ No

   Comments:

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
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	☐	10 — Regional Reliability Organizations, Regional Entities

Group Comments (Complete this page if comments are from a group.)	
Group Name:	Midwest Reliability Organization
Lead Contact:	**Dick Pursley**
Contact Organization:	**MRO for Group (Great River Energy for Contact)**
Contact Segment:	**10**
Contact Telephone:	**763.241.2249**
Contact E-mail:	**dpursley@grenergy.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
Neal Balu	**WPSR**	**MRO**	10
Terry Bilke	**MISO**	**MRO**	10
Alan Boesch	**NPPD**	**MRO**	10
Robert Coish, Chair	**MHEB**	**MRO**	10
Carol Gerou	**MP**	**MRO**	10
Ken Goldsmith	**ALT**	**MRO**	10
Todd Gosnell	**OPPD**	**MRO**	10
Jim Haigh	**WAPA**	**MRO**	10
Tom Mielnik	**MEC**	**MRO**	10
Pam Oreschnick	**XEL**	**MRO**	10
Dave Rudolph	**BEPC**	**MRO**	10
Eric Ruskamp	**LES**	**MRO**	10
Joe Knight	**MRO**	**MRO**	10
27 Additional MRO Members	**Not Named Above**	**MRO**	10

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FERC staff report

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Stakeholder Comments

- Reliability Coordinator vs. Regional Reliability Organization
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1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☒ Yes

   ☒ No

   Comments: The scope of this SAR would have been better defined if the complete Standard Review Form for the Vegetation Management Standard had been included as an attachment to the SAR. Several issues in the Standard Review Form for this SAR were excluded with this posted SAR. For example, issues related to R3.1 and R3.2.

   The MRO is also not clear on the scope of the instruction to the SDT to "Expand the applicability to include transmission lines operated at 200 kV and above and other facilities as determined by the ERO so that the Reliability Standard applies to Bulk-Power System transmission lines that have an impact on reliability" It is not clear to the MRO what is meant by "as determined by the ERO". What process will the ERO use? The ERO should use stakeholder input to make this determination. The current standard is applicable to all transmission lines 200 kV and above and to any lower voltage lines designated by the RRO as critical to the electric system in the region. Will the ERO be in a position to assume the assessment of the criticality of lines less than 200 kV without input from the entities that have historically operated in each region?

   Also, the MRO is not clear on what is included in the term Bulk-Power System. What guidance will the SDT have in determining what is meant by the Bulk-Power System? Since this relates to the large issue of the Bulk Electric System versus Bulk-Power System is this SAR the appropriate vehicle to address this issue? There should be a wider discussion and resolution to this issue for consistent application to all standards by all SDTs.

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

   ☒ Yes

   ☐ No

   Comments: Since the IEEE standard does not appear to be a favorable clearance requirement, minimum clearance requirements should be tied to legal documents such as easments, state statute, or permits. This will help Transmission Owners to maintain their ROWs based on their agreements with the land owners and not rely on historical ROW management practices. It would also provide flexibility in clearance requirements based on geopraphical and climatological factors that influence different regions because landowner agreements will be different depending on local influences.

Comment Form — 1st Posting of SAR for Revisions to Vegetation Management FAC-003-1

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Organization:		
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NERC Region		**Registered Ballot Body Segment**
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Group Comments (Complete this page if comments are from a group.)

Group Name: Florida Power and Light Company

Lead Contact: **John Tamsberg**

Contact Organization: **Florida Power and Light Company**

Contact Segment: **1**

Contact Telephone: **(561) 694-3975**

Contact E-mail: **john_tamsberg@fpl.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
Marty Mennes, PE.		FRCC	1
Barbara Jaindl, PE.		FRCC	1
Michael Warr, PE.		FRCC	1
Greg Keller, PE.		FRCC	1

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Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments: FPL recognizes the need to address the concerns outlined in the NOPR and by the FERC Staff.

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: Establishing minimum inspection cycles is a very problematic given the large variety of vegetative conditions throughout North America. In reality most lines are inspected annually for all failure modes including vegetation. The trees that played a part of the North East Blackout were known and on the radar screen. The utility failed to take action. The inspection did not prevent the outage from occurring. The failure to take action on the known site condition was the contributing factor to the Blackout.

   We do not understand the need to establish separate criteria other than the RRO’s critical designation. A transmission line is either necessary to the system to prevent an overload situation or it is not. To add lines that might not be critical to the system would dilute the effort needed to insure that the critical lines are properly maintained. Since system stability is the focus of the standard, what criteria would be used to bring additional lower voltage lines under the standard.

   When developing Clearance 2, the committee needed to determine a distance at which a Transmission Owner could be out of compliance even though no interruption has occurred. In a sense this is the maximum ‘speed limit’ at which the utility would be in violation. Their criteria was “How close can a tree be and not cause an outage?” The engineers on the team reviewed scientific data and current standards. The IEEE MAID standard was the consensus selection of the sub committee. All parties need to understand that this is one of the building blocks that would be used in determining the width of an easement or ROW. Picking the ANSI Z133.1 Table 1 or 2 as the NOPR suggests could immediately place thousands of miles of transmission lines out of compliance that have performed satisfactorily for years. The ANSI tables are phase to phase safety calculations when grow-in tree interruptions are phase to ground situations.

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

☒ Yes

☐ No

Comments: Requirement 3.2 exempts reporting of outages from outside the ROW when natural disasters such as tornados or hurricanes occur. Our experience with numerous hurricanes indicates that all outages during these types of events should be exempt. The focus in these situations is to get the lines back in service and restore customers. There is insufficient manpower to adequately complete the forensics necessary to determine an accurate root cause. It is not uncommon to find vegetation debris in the lines or downed trees on the ROW in this situation. In most cases it is not possible to determine the original location of these trees.

In the compliance section of the document a transmission owner becomes non compliant with a single category 1 or 2 outage. This occurs regardless of the circumstances. A non compliant penalty for a single outage in a situation where no customers were affected and the system could not have been compromised is not reasonable. It is also not an indicator of a poorly maintained system. We agree that several Category 1 or 2 interruptions could be an indicator of neglect but one is not. We recommend that The compliance section be reviewed with this in mind.

Comment Form — 1st Posting of SAR for Revisions to Vegetation Management FAC-003-1

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<table>
<tr><th colspan="3">Individual Commenter Information
(Complete this page for comments from one organization or individual.)</th></tr>
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<tr><td colspan="3">Organization:</td></tr>
<tr><td colspan="3">Telephone:</td></tr>
<tr><td colspan="3">E-mail:</td></tr>
<tr><td>NERC Region</td><td></td><td>Registered Ballot Body Segment</td></tr>
<tr><td rowspan="10">☐ ERCOT
☐ FRCC
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☐ RFC
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☐ NA – Not Applicable</td><td>☐</td><td>1 — Transmission Owners</td></tr>
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<tr><td colspan="3"></td></tr>
</table>

Group Comments (Complete this page if comments are from a group.)

Group Name: FRCC

Lead Contact: **Eric Senkowicz**

Contact Organization: **FRCC**

Contact Segment: **10**

Contact Telephone: **813-289-5644**

Contact E-mail: **esenkowicz@frcc.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
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Clark Hawkins	**Lee County Electric Cooperative**	**FRCC**	3
Mark Bennett	**Gainesville Regional Utilities**	**FRCC**	5
Pedro Modia	**Florida Power and Light**	**FRCC**	1

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

FAC-003-1 is a relatively new standard that was approved in 2006. FAC-003 has some "fill-in-the-blank" components to eliminate. In addition, the following comments submitted by FERC and stakeholders need to be addressed in the refinement of the standard:

FERC NOPR

- Develop a minimum vegetation inspection cycle that allows variation for physical differences, as discussed above; and
- Remove the applicability to transmission lines operated at 200 kV and above so that the Reliability Standard applies to bulk power system transmission lines that have an impact of reliability as determined by the ERO.

FERC staff report

- Objections to use of IEEE standard

Stakeholder Comments

- Reliability Coordinator vs. Regional Reliability Organization
- Too weak on compliance
- Format inconsistencies

The improvements to the standard should bring the standard's format and elements into conformance with the latest version of the *Reliability Standards Development Procedure* and the ERO Rules of Procedure.

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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:
   NERC as the ERO along with its regulated stakeholders need to use the Standards Process to continue refining the industry's suite of standards, especially to address inconsistencies within the standards. The process also serves to address real or perceived reliability concerns in a balanced and open forum.

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: As stated in this SAR comment form, the improvements should be made to bring the standard into conformance with the Reliability Standards Development Procedure which at this time is version 6.0, adopted by NERC BOT, 11/1/2006. The SAR scope via the attached Standard Review Guidelines includes two areas not defined within the procedure. The Mitigation Time Horizons and definitions for the violation severity levels (VSLs), Lower, Moderate, High and Severe.

   We understand the description of Mitigation Time Horizons and definitions for VSLs are included in the SAR (the concept of Violation Time Horizons is included in the Sanctions Guidelines, appendix 4B, NERC Compliance Filing to FERC dated October 18th, 2006), but these discrepancies are part of a broader policy issue and since their use is not clearly stipulated in the NERC Reliability Standards Development Procedure, including them in the scope of the SAR is premature and will cause unnecessary confusion to stakeholders and regulators.

   The process is requesting the industry to comment on a scope that is defined outside the reliability standards process and as such is subject to revisions and interpretations outside the process as well. This appears inappropriate and at the extreme will lead to inconsistent understanding, measurement and enforcement of compliance actions.

   The Mitigation Time Horizons and VSL levels should be defined in the Reliability Standards Development Procedure prior to inclusion in the scope of a SAR.

   Specific Items Within Current SAR Scope:

   The establishment of minimum inspection cycles has been addressed previously, in the development of the current standard and was found very problematic given the large variety of vegetative conditions throughout North America. The vegetation that was identified as a contributing cause to the 2003 Northeast Blackout had already been identified by previous inspection activities. It was the failure to take action on the known site conditions that contributed to the event. Therefore, a minimum inspection cycle would still NOT have prevented or mitigated the scope of the Blackout.

The current 200 kV threshold ensures that vegetation management efforts are focused on the critical bulk power transfer lines and that TVM efforts are not diluted by including additional lower voltage lines. In practicality, the RRO designation process provides the necessary flexibility to the Regions to address localized areas where bulk power system reliability may be compromised by lower voltage vegetation outages. To note as well, Northeast Blackout related vegetation outages which initiated the cascade occurred on lines that operate at 345 kV, well above the current threshold.

The FRCC supported the development of Clearance 2, as established in the current standard, as this was a consensus selection by not only the subject matter experts, but many industry participants. Picking the ANSI Z133.1 Table 1 or 2 as the NOPR suggests, could immediately place thousands of miles of transmission lines out of compliance even though operating data indicates that the lines have performed satisfactorily for years. The concern would be, the resulting dilution of valuable industry and regulator resources.

The SAR includes the following stakeholder comment: "Too weak on compliance" .
We caution that we feel the compliance section does need refining, but that in a world of limited resources should focus on trends in vegetation outages and not necessarily on single outages. For transmission owners, two outages on a radial 230 kV circuit should not carry the same penalty as eight outages on multiple 230 kV circuits within a network. We would recommend that compliance be refined to identify trends, relevance and risk probability to help the industry focus their resources appropriately.

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

☒ Yes

☐ No

Comments:
Requirement 3.2, item (1), the reporting exemption for outages occuring due to natural disaters should be expanded to include all vegetation outages that occur as a result of the disaster. Currently the exemption applies to vegetation from outside the ROW.

As a result of significant experience with hurricanes, our operators have found that this distinction results in a waste of post-disaster resources. The standard currently requires the owner to investigate and determine the original location of the vegetation that may have caused an outage. Restoration of circuits may be delayed and often times, determination of the original location of the vegetation is not possible .

Please use this form to submit comments on the Vegetation Management SAR. Comments must be submitted by **February 14, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Vegetation Management" in the subject line. If you have questions, please contact Richard Schneider at richard.schneider@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
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E-mail:	mspector@cenhud.com	

NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs,
☐ **MRO**	☒	3 — Load-serving Entities
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Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: The proposed revisions listed under the FERC NOPR do not provide proper justification to alter the requirements in the current FAC-003-1 document that was adopted one year ago.

   First, "a minimum vegatation inspection cycle that allows variation in physical difference" is already called for under the current standard. As stated in Section R1.1. of FAC-003-1, a schedule already should be defined under the transmission vegetation management program (TVMP). This schedule already allows for "variation in physical difference" since the current standard states that "this schedule should be flexible enough to adjust for changing conditions."

   Secondly, under Applicability Section 4.3., the current standard already allows for lines with lower voltage than 200kV to be "designated by the RRO as critical" and therefore applicable to the standard. Removal of the 200kV benchmark is not needed.

   And lastly, under the FERC staff report, the IEEE standard provides guidance in clearances and has been the industry standard for many years. If FERC objects to using this standard then they should provide clearances that can be discussed and agreed upon by the transmission owners.

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: See comments above.

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

   ☐ Yes

   ☒ No

   Comments:

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
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NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
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1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: There was no empirical or anecdotal evidence presented by FERC staff to support the Commission's view that the reliability of the Bulk Power System will be enhanced with further revisions to FAC-003-1. This standard was the subject of vigorous industry debate in a previous SAR. Although it is far from perfect, the proposed revisions will not improve reliability and may very well damage existing VM programs.

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: The Commission's reccomendation to develop a "minimum" vegetation inspection cycle is untimely and their proposal to revise the scope ignores plain language contained in the standard.

   In SCE’s view, the Commission's incessant need to bolt on a "widget count" requirement (for minimum inspection cylcles) will likely lead to an increased number of tree-to-line contacts. Unlike the static equipment located in power plants and substations, trees and foliage in and around Transmission ROWs are subject to uncontrolable and fairly unpredictable natural forces. Industry debate during the previous SAR and comments submitted in the recently concluded NOPR demonstrate this approach is unsound. Transmission Owners in neighboring states commented that their cycles and trimming protocols vary from year to year and sometimes circuit to circuit. Instituting a minimum inspection cycle of 3 years (for example) might appeal to certain TOs because doing so will support a case for increased rate recovery. But for others, a mandatory 3 year inspection cycle will offer a potential cost reduction opportunity because they are already following a voluntary 2 year inspection cycle.

   The Commission's other reccomendedation should be rejected because subsection 4.3 clearly covers transmission lines operating below 200 kV. ["….any lower voltage lines designated by the RRO as critical to the reliabilty of the electric system in the region.”]

   FAC-003-1 requires Transmission Owners to - “define a schedule for and the type (aerial, ground) of ROW vegetation inspections”. Although the Commission staff would prefer a specific time duration because it suits their "check list" style of enforcement, the prudent thing to do is allow TOs the latitude to manage their part of the bulk system and hold each accountable to the existing compliance measures in FAC-003-1. Similarly, revising subsection 4.3 in deferrence to the Commission's or staff's misinterpretation of plain text is unwarranted.

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

   ☐ Yes

   ☒ No

   Comments: Although SCE is wholly dissatisfied with the integration of IEEE 516-2003 into FAC-003-1 and looks forward to the day when qualified industry professionals and utility arborists are provided an opportunity to develop a reasonable and scientifically sound method for determining “minimum” tree-to-line clearances, we believe this standard should be allowed to “soak” a bit before subjecting it to further revision.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: The current standard contains appropriate levels of guidelines and penalties to ensure the owners vegetation management program is implemented and managed to ensure the reliability of the transmission system. Mandating inspection cycle frequencies will not enhance nor ensure reliability by inspecting more or less frequently. The minimum vegetation clearances at maximum operating conditions that are established within the owner's program that are auditable by the ERO will ensure reliability. By adding lines other than those >200KV may reduce the focus on those lines and impact the budget dollars allocated to focus on the lines >200KV. Generally easements are much more narrow on lower voltage lines, the impact on budget dollars would often require more emphasis on these lines. This may have an effect on the ability to focus clearing efforts on those lines that will have a much greater impact on the bulk power system. The IEEE standard when used as the minimum clearance distance at maximum operating condition will ensure reliability when these clearances are maintained by vegetation management activities.

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments:
   Minimum Inspection Intervals:
   Progress Energy believes that this standard provides the proper amount of flexibility regarding vegetation inspection cycles and that the FAC-003 standard revision should not develop minimum inspection intervals on a continent with such regional diversity in climate and plant life.

   The purpose of Requirement 1.1 of standard FAC-003-1 is to put the responsibility for proper inspection cycles on the entity that knows the local conditions and can best define what that inspection frequency should be, the Transmission Owner. Both NERC and the FERC staff have recognized that various local conditions can have an affect on the determination of adequate inspection frequencies. Establishing a mandatory minimum inspection frequency could have two detrimental effects on the industry.

   First, where a particular region is heavily forested and has heavy rainfall along with extended or year round growing seasons, a "back stop" minimum inspection frequency could lead transmission owners to conduct inspections less frequently than what the local conditions require. This could result in a Transmission Owner complying with the standard while not adequately protecting the reliability of that region's transmission system. This is a "lowest common denominator" approach which FERC has repeatedly stated is inappropriate for the reliability standards.

Second, where a particular region is arid, sparsely forested or has a minimum growing season, a “back stop” minimum could require a more frequent interval than is realistically needed. This would result in increased and unnecessary costs for electric utility customers without providing an increase in system reliability.

In its discussion of inspection intervals, FERC indicates that a “one-year vegetation inspection cycle is reasonable.” NOPR, P 383. The Commission continues by stating “a one-year inspection cycle is the ‘norm’ for the industry, but not the lowest common denominator…” It follows from this observation that the industry as a whole recognizes and follows appropriate inspection intervals without a need to change the standard. Further, FERC also states “some variation to a continent-wide, one-year minimum inspection cycle should be allowed due to physical differences such as climate and species of vegetation.” NOPR, P 382. FERC’s express recognition that a “one size fits all” approach is not appropriate further supports Progress Energy’s contention that the existing inspection requirements in standard FAC-003 should remain unchanged.

Finally, the performance metrics of proposed standard FAC-003 require the reporting of applicable transmission interruptions that are caused by vegetation. This process should appropriately identify Transmission Owners’ inspection cycles that are not adequate. In this event, the ERO has the authority to engage the Transmission Owner in enforcement compliance actions and, therefore, can remedy any vegetation-related outage that is attributed to the Transmission Owner’s inspection frequency.

Standard Applicability:
Progress Energy disagrees with the proposal to revise the 200 kV guidepost for determining facilities subject to this standard.

The majority of transmission facilities below 200 kV have significantly different design/construction/operating characteristics and have not been cited as impacting bulk power system reliability. For example, the 2003 DOE “Blackout Report,” and all referenced major blackouts in the Report, cited only outages which involved vegetation at line voltages above 200 kV. The characteristics of lines below 200 kV will result in significant documentation and reporting of items such as restrictions, mitigation plans, off right-of-way vegetation-related outage investigation/information and other issues, all of which dilutes the focus on lines that directly impact bulk power system reliability.

Revising the standard to use general criteria or broad language for defining "Bulk Power System" transmission lines covered by the standard could become a “one size fits all” approach. If that approach were taken, the standard would cover a significant number of transmission lines that have no direct impact on bulk power system reliability under standard planning/operating conditions, resulting in a significant increase in costs for electric customers without improving “Bulk Power System” system reliability. Progress Energy believes that the applicability provision of the standard should instead focus attention of the standard only on the transmission lines below 200 kV that directly impact “Bulk Power System” reliability, as the current version requires.

In sum, while Progress Energy recognizes some validity in the Commission’s concern, Progress Energy recommends that the applicability provision of this standard should be revised only if existing system design, planning or operating reliability criteria and parameters are considered as a basis for defining the applicability of the standard. For example, it may be appropriate to limit the applicability of the standard to all lines that are operated at 200 kV and above and to operationally significant circuits between 100 kV and 200 KV that are elements of Interconnection Reliability Operating Limits (“IROLs”).

IEEE Standard for Minimum Clearances:
Progress Energy disagrees with objections in the FERC staff report to the use of the IEEE 516-2003 clearance as the minimum acceptable distances for “Clearance 2”. The IEEE

516-2003 tables are appropriate for defining the minimum acceptable clearances to prevent flashover between conductors and vegetation under all rated electrical operating conditions. Closer minimum clearances such as the minimum length of a support insulator could have been adopted as a "lowest common denominator" clearance. However the clearance in IEEE 516-2003 was adopted to ensure an additional margin of reliability. FERC staff references ANSI Z-133 which is a safety standard that addresses worker safety as well as the safety of the general public. As such, the purpose of ANSI Z-133 is to address safety and is not focused on transmission line reliability, which is the purpose of FAC-003-1. OSHA, NESC and other related safety standards have clearances in excess of IEEE 516-2003. Those clearances are clearly focused on safety issues and will still apply to other aspects of design and operation of electric facilities (such as public and worker safety) but do not need to be referenced in a vegetation management reliability standard. Reliability standards are not the appropriate forum for addressing safety standards or issues, such as worker safety. The reliability standards should focus on reliability issues.

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

☒ Yes

☐ No

Comments: Standard Applicability:
The outage reporting requirement for the RRO should be deleted. Making FAC-003 applicable to the RRO is in violation of the legislation that established the ERO. This legislation states that enforceable standards can apply only to owners, users and opeartors of the bulk power system. Futher, in the NOPR on NERC standards, FERC declined to approve those standards that applied to the RROs, in part because the RROs are not owners, users or operators.

Compliance:
Progress Energy believes that FAC-003 should focus compliance on the issues that improve system/grid reliability. The VM standard outage reporting requirements do not focus on ensuring grid/network reliability.
Category 2 outages ("Fall-ins" from vegetation within the R/W) result in a level of non-compliance (Level 2 or 3). However, "Fall-ins", either off-R/W or within the R/W, are random events. They would not occur sequentially (i.e., a fall-in causing another line section to overload resulting in another "fall-in") and would not have the potential to cascade into a widespread blackout. This is a customer reliability issue for that line, not a grid reliability issue. While it may be worthwhile to report for tracking and trending, it is not an outage that should result in non-compliance.
Category 1 "Grow-ins" include outages that result from conductor side-wing would be reported as Category 1 outages, resulting in non-compliance (Level 3 or 4). However, conductor side-swing outages are random occurrences. They are not the sequential outages that would have the potential to cascade into a widespread blackout. This is a customer reliability issue for that line, not a grid reliability issue.
These types of outages should be not be considered any different than numerous other random events that result in transmission line outages.

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Richard Mider	
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NERC Region		**Registered Ballot Body Segment**
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   ☐ Yes
   ☒ No

   Comments: The current draft FAC 003 1 will provide a high level of reliability for the transmission bulk delivery system which the public now expects. After a comprehensive industry rewiew which included industry balloting, the current Vegetaion Management Standard 003 1 was approved in Feburary 2006 and several sections did not go in to effect for one year (2007). Sufficient time should be allowed so that impact of the current standard can be monitored.
   FAC 003 1 was designed to prevent cascading type outages and by establishing a standard for 200KV lines and above catastrophic type power outages will be eliminated. Lower volatge lines can be placed under this standard when the impact on the bulk delivery system requires tighter management as determined by local reliability organizations. Inspection cycles must be designed to meet regional needs based on local conditons, and the current standard provides this flexiblity.

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☐ Yes
   ☒ No

   Comments: The current standard FAC 003 1 should be monitored for one to two full years after all segments have been implemented. February 14, 2007 is too soon to determine if a revision is required.
   The standard should apply to 200 KV lines and higher voltages to prevent cascading type power outages.
   The IEEE table 516 is referenced as a minimum guide for table 2 clearances. This table provides clear and measurable distances that can used for audits and potential compliance issues. The current standard allows enough flexibility so that the clearance 2 distance can be expanded if a utility feels that is the correct approach in a specfic region.
   The physical differences between electric systems, tree growth rates, local regulations, climate, and geography make it important to provide a flexible standard, a "one size fits all" approach will not be effective in the long run.

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

   ☐ Yes
   ☒ No

Comments: The Vegetation Management Standard FAC 003 1 is comprehensive, and utilities following the established guidelines will be able to meet FERC's expecation of preventing bulk power delivery outages by using crisp measurable guidleines that offer limited flexiblity for varying conditions.

Comment Form — 1st Posting of SAR for Revisions to Vegetation Management FAC-003-1

Please use this form to submit comments on the Vegetation Management SAR. Comments must be submitted by **February 14, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Vegetation Management" in the subject line. If you have questions, please contact Richard Schneider at richard.schneider@nerc.net or by telephone at 609-452-8060.

<table>
<tr><th colspan="3">Individual Commenter Information
(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td colspan="3">Name:</td></tr>
<tr><td colspan="3">Organization:</td></tr>
<tr><td colspan="3">Telephone:</td></tr>
<tr><td colspan="3">E-mail:</td></tr>
<tr><td>NERC Region</td><td></td><td>Registered Ballot Body Segment</td></tr>
<tr><td rowspan="10">☐ ERCOT
☐ FRCC
☐ MRO
☐ NPCC
☐ RFC
☒ SERC
☐ SPP
☐ WECC
☐ NA – Not Applicable</td><td>☒</td><td>1 — Transmission Owners</td></tr>
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<tr><td>☐</td><td>3 — Load-serving Entities</td></tr>
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<tr><td>☐</td><td>10 — Regional Reliability Organizations, Regional Entities</td></tr>
</table>

Group Comments (Complete this page if comments are from a group.)

Group Name:	Southern Company Transmission
Lead Contact:	**Roman Carter**
Contact Organization:	**Southern Co. Transmission**
Contact Segment:	**1**
Contact Telephone:	**205-257-6027**
Contact E-mail:	**jrcarter@southernco.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
Roman Carter	Southern Company Transmission	SERC	1
Steve Burns	Gulf Power Co.	SERC	1
Randall Gann	Alabama Power Co.	SERC	1
John West	Georgia Power Co.	SERC	1
Marc Butts	Southern Co. Transmission	SERC	1
JT Wood	Southern Co. Trans.	SERC	1
Jim Busbin	Southern Co. Trans.	SERC	1

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

FAC-003-1 is a relatively new standard that was approved in 2006. FAC-003 has some "fill-in-the-blank" components to eliminate. In addition, the following comments submitted by FERC and stakeholders need to be addressed in the refinement of the standard:

FERC NOPR

- Develop a minimum vegetation inspection cycle that allows variation for physical differences, as discussed above; and
- Remove the applicability to transmission lines operated at 200 kV and above so that the Reliability Standard applies to bulk power system transmission lines that have an impact of reliability as determined by the ERO.

FERC staff report

- Objections to use of IEEE standard

Stakeholder Comments

- Reliability Coordinator vs. Regional Reliability Organization
- Too weak on compliance
- Format inconsistencies

The improvements to the standard should bring the standard's format and elements into conformance with the latest version of the *Reliability Standards Development Procedure* and the ERO Rules of Procedure.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☒ Yes

   ☒ No

   Comments: We are not sure what you are asking? If you are asking whether we support the standard as it exists today-Southern does! If you are asking whether Southern Co. supports the changes being recommended in this Standard-we DON"T.

   The present standard appears to be serving its intended purpose and the industry as currently written. The standard should not be revised until it has demonstrated it is ineffective or inadequate for ensuring the reliability of the nation's transmssion grid.

   Any changes to the standard should be based on empirical data rather than the assumption that the Standard is not serving its intended purpose. The standard has not been in effect long enough to determine if it is ineffective.

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: The scope of the SAR should be limited to formatting and changes of wording that recognize the formation of the ERO and its procedures.

   The drafting team should not attempt to re-write the present clearance requirements, which are based on IEEE flashover distances. The clearance requirements in the orignal standard were written through extensive evaluation and input from the industry. There was strong industry consensus on the present language and the standard is serving its intended purpose very well. The clearance standard should not be revised until it is found to be ineffective or inadequate.

   The drafting team should not attempt to change the applicability of the present standard. The present standard applies to all 200 KV and higher lines, plus any other line the Regional Entity deems critical. A change in wording to make the standard apply to any bulk power system transmission line deemed critical by the ERO does not provide any additional safeguard that is not already contained in the standard as presently written.

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

   ☐ Yes

☒ No

Comments:

Please use this form to submit comments on the Vegetation Management SAR. Comments must be submitted by **February 14, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Vegetation Management" in the subject line. If you have questions, please contact Richard Schneider at richard.schneider@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Ron Falsetti	
Organization:	IESO Ontario	
Telephone:	905 855-6187	
E-mail:	ron.falsetti@ieso.ca	

NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs, ISOs,
☐ **MRO**	☐	3 — Load-serving Entities
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	☐	10 — Regional Reliability Organizations, Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

FAC-003-1 is a relatively new standard that was approved in 2006. FAC-003 has some "fill-in-the-blank" components to eliminate. In addition, the following comments submitted by FERC and stakeholders need to be addressed in the refinement of the standard:

FERC NOPR
- Develop a minimum vegetation inspection cycle that allows variation for physical differences, as discussed above; and
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FERC staff report
- Objections to use of IEEE standard

Stakeholder Comments
- Reliability Coordinator vs. Regional Reliability Organization
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The improvements to the standard should bring the standard's format and elements into conformance with the latest version of the *Reliability Standards Development Procedure* and the ERO Rules of Procedure.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments:
   With respect to the item in the Brief Description section under FERC NOPR:
   "Remove the applicability to transmission lines operated at 200 kV and above so that the Reliability Standard applies to Bulk Power System transmission lines that have an impact on reliability as determined by the ERO." It is the IESO's view that requiring the ERO to make these determinations, is inappropriate. We believe the standard should remain applicable to lines 200 kV and above and lines below 200 kV as determined by the Reliability Coordinator, similar to the PRC-023 standard.

   The IESO also suggests that it be made clear in the SAR that it will be a complete review of the subject requirements: to include the addition, deletion and modification of requirements, as agreed to by public consensus.

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

   ☐ Yes

   ☒ No

   Comments:

Comment Form — 1st Posting of SAR for Revisions to Vegetation Management FAC-003-1

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Mike Gentry	
Organization:	Salt River Project	
Telephone:	602-236-6408	
E-mail:	Mike.Gentry@srpnet.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs,
☐ **MRO**	☐	3 — Load-serving Entities
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

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- Develop a minimum vegetation inspection cycle that allows variation for physical differences, as discussed above; and
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FERC staff report

- Objections to use of IEEE standard

Stakeholder Comments

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- Too weak on compliance
- Format inconsistencies

The improvements to the standard should bring the standard’s format and elements into conformance with the latest version of the *Reliability Standards Development Procedure* and the ERO Rules of Procedure.

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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

   ☐ Yes

   ☒ No

   Comments:

Please use this form to submit comments on the Vegetation Management SAR. Comments must be submitted by **February 14, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Vegetation Management" in the subject line. If you have questions, please contact Richard Schneider at richard.schneider@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name: Richard Dearman		
Organization: Tennessee Valley Authority		
Telephone: 256-519-2067		
E-mail: redearman@tva.gov		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs,
☐ **MRO**	☐	3 — Load-serving Entities
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Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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FERC NOPR

- Develop a minimum vegetation inspection cycle that allows variation for physical differences, as discussed above; and
- Remove the applicability to transmission lines operated at 200 kV and above so that the Reliability Standard applies to bulk power system transmission lines that have an impact of reliability as determined by the ERO.

FERC staff report

- Objections to use of IEEE standard

Stakeholder Comments

- Reliability Coordinator vs. Regional Reliability Organization
- Too weak on compliance
- Format inconsistencies

The improvements to the standard should bring the standard's format and elements into conformance with the latest version of the *Reliability Standards Development Procedure* and the ERO Rules of Procedure.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☒ Yes

   ☒ No

   Comments: As worded this question is confusing however the following comments are presented on the SAR:

   The current standard contains appropriate requirements and measures to ensure that vegetation related outages will not cause cascading transmission blackouts. Mandating new expiicit inspection cycle frequencies will not enhance nor ensure reliability by inspecting more or less frequently. The current minimum vegetation clearances at maximum operating conditions that are established within the owner's program, which is auditable by the ERO, is sufficient to prevent vegetation related cascading transmission blackouts. Extending the requirements to a much a larger population of lines would reduce the current focus on the most important lines (those >200 kV). The IEEE standard when used as the minimum vegetation clearance distance at maximum operating condition will ensure desired performance of the lines. A standard of zero tolerance for vegetaion related outages in the ROW is not a weak standard on compliance.

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: Minimum Inspection Intervals:

   FAC 003-1 provides the proper amount of flexibility regarding vegetation inspection cycles and that the Standards Drafting Team should not impose minimum inspection intervals on a continent with such regional diversity in climate and plant life.

   Requirement 1.1 of standard FAC-003-1 places the responsibility for proper inspection cycles on the entity that knows the local conditions and can best define what that inspection frequency should be, the Transmission Owner. Both NERC and the FERC staff have recognized that various local conditions can have an affect on the determination of adequate inspection frequencies. Establishing a mandatory minimum inspection frequency could have two detrimental effects on the industry.

   First, where a particular region is heavily forested and has heavy rainfall along with extended or year round growing seasons, a "back stop" minimum inspection frequency could lead transmission owners to conduct inspections less frequently than required by the local conditions. This could result in a Transmission Owner complying with the standard while not adequately protecting the reliability of that region's transmission system. This is a "lowest common denominator" approach which FERC has repeatedly stated is inappropriate for the reliability standards.

Second, where a particular region is arid, sparsely forested or has a minimum growing season, a "back stop" minimum could require a more frequent interval than is realistically needed. This would result in increased and unnecessary costs for electric utility customers without providing an increase in system reliability.

In its discussion of inspection intervals, FERC indicates that a "one-year vegetation inspection cycle is reasonable." FERC NOPR, 10/20/2002 paragraph 383. The Commission continues by stating "a one-year inspection cycle is the 'norm' for the industry, but not the lowest common denominator…" It follows from this observation that the industry as a whole recognizes and follows appropriate inspection intervals without a need to change the standard. Further, FERC also states "some variation to a continent-wide, one-year minimum inspection cycle should be allowed due to physical differences such as climate and species of vegetation." FERC NOPR 10/20/2006, paragraph 382. FERC's recognition that a "one size fits all" approach is not appropriate supports maintaining the existing inspection requirements in standard FAC-003-1.

Finally, the performance metrics of FAC-003 require the reporting of applicable transmission interruptions that are caused by vegetation. This process will identify Transmission Owners' inspection cycles that are not adequate. In this event, the ERO has the authority to engage the Transmission Owner in enforcement compliance actions and, therefore, can remedy any vegetation-related outage that is attributed to the Transmission Owner's inspection frequency.

Standard Applicability:
The 200 kV threshold for determining facilities subject to this standard should not be revised.

The transmission facilities below 200 kV have not been cited as impacting bulk power system reliability. The Final Report on the August 14, 2003 Blackout in the United states and Canada: Causes and Recommendations April 2004 by the U.S.- Canada Power System Outage Task Force and all referenced major blackouts(pages 103-115) in that report, cited only outages which involved vegetation at line voltages above 200 kV. Generally applying requirements appropriate for 200 kV lines to lines less than 200 kV will result in significant documentation and reporting of items such as restrictions, mitigation plans, off right-of-way vegetation-related outage investigation/information and other issues, all of which dilutes the focus on lines that directly impact bulk power system reliability.

Revising the standard to use general criteria or broad language for defining "Bulk Power System" transmission lines covered by the standard could become a "one size fits all" approach. If that approach were taken, the standard would cover a significant number of transmission lines that have no direct impact on bulk power system reliability under standard planning/operating conditions, resulting in a significant increase in costs for electric customers without improving "Bulk Power System" system reliability. The SERC VMS believes that the applicability provision of the standard should instead focus attention of the standard only on the transmission lines below 200 kV that directly impact "Bulk Power System" reliability, as the current version requires.

The applicability provision of this standard should be revised only if existing system design, planning or operating reliability criteria and parameters are considered as a basis for defining the applicability of the standard. To that end, each Regional Entity (RE) should determine the applicability of FAC-003 to those lines within the region that are between 100 kV and 200 KV if and only if they are identified as operationally significant elements of Interconnection Reliability Operating Limits ("IROLs").

IEEE Standard for Minimum Clearances:

The IEEE 516-2003 should continue to be used as the minimum acceptable distances for "Clearance 2". The IEEE 516-2003 tables are appropriate for defining the minimum acceptable clearances to prevent flashover between conductors and vegetation under all rated electrical operating conditions. Closer minimum clearances such as the minimum length of a support insulator could have been adopted as a "lowest common denominator" clearance. However the clearance in IEEE 516-2003 was adopted to ensure an additional margin of reliability. FERC staff references ANSI Z-133 which is a safety standard that addresses worker safety as well as the safety of the general public. As such, the purpose of ANSI Z-133 is to address worker safety and is not focused on transmission line reliability, which is the purpose of FAC-003-1. OSHA, NESC and other related safety standards have clearances in excess of IEEE 516-2003. Those clearances are clearly focused on safety issues and will still apply to other aspects of design and operation of electric facilities (such as public and worker safety) but do not need to be referenced in a vegetation management reliability standard.

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

   ☒ Yes

   ☐ No

   Comments: Standard Applicability:
   The outage reporting requirement for the RRO should be deleted. Making FAC-003 applicable to the RRO is in violation of the legislation that established the ERO. This legislation states that enforceable standards can apply only to owners, users and operators of the bulk power system. Futher, in the NOPR on NERC standards, FERC declined to approve those standards that applied to the RROs, in part because the RROs are not owners, users or operators.

   Compliance:
   Reporting requirements for Category 3 outages should be eliminated. These outages are not controllable, not relevant to compliance, not related to grid reliability, not related to cascading blackouts, and such reporting leads to unnecessarily biasing reliability related information.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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Organization:		
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NERC Region		**Registered Ballot Body Segment**
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Group Comments (Complete this page if comments are from a group.)

Group Name: SERC Vegetation Management Subcommittee

Lead Contact: **Richard Dearman**

Contact Organization: **TVA**

Contact Segment: **1**

Contact Telephone: **256-519-2067**

Contact E-mail: **redearman@tva.gov**

Additional Member Name	Additional Member Organization	Region*	Segment*
Jay Farrington	Alabama Electric Coop	SERC	1
Randy Gann	Alabama Power Co.	SERC	1
Raymond Wiesehan	Ameren	SERC	1
John Neagle	Associated Electric Coop	SERC	1
Billy George	Duke Energy Carolinas	SERC	1
Ralph Hale	Entergy	SERC	1
Marc Tunstall	Fayetteville PWC	SERC	1
Jack Gardner	Progress Energy Carolinas	SERC	1
Jerry Lindler	SCE&G	SERC	1

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

FAC-003-1 is a relatively new standard that was approved in 2006. FAC-003 has some "fill-in-the-blank" components to eliminate. In addition, the following comments submitted by FERC and stakeholders need to be addressed in the refinement of the standard:

FERC NOPR

- Develop a minimum vegetation inspection cycle that allows variation for physical differences, as discussed above; and
- Remove the applicability to transmission lines operated at 200 kV and above so that the Reliability Standard applies to bulk power system transmission lines that have an impact of reliability as determined by the ERO.

FERC staff report

- Objections to use of IEEE standard

Stakeholder Comments

- Reliability Coordinator vs. Regional Reliability Organization
- Too weak on compliance
- Format inconsistencies

The improvements to the standard should bring the standard's format and elements into conformance with the latest version of the *Reliability Standards Development Procedure* and the ERO Rules of Procedure.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☒ Yes

   ☒ No

   Comments: The SERC VMS is unsure how to answer the question as it is worded, but has the following comments on the SAR:

   The current standard contains appropriate requirements and measures to ensure the owners vegetation management program is implemented and managed to ensure the reliability of the transmission system. Mandating inspection cycle frequencies will not enhance nor ensure reliability by inspecting more or less frequently. The minimum vegetation clearances at maximum operating conditions that are established within the owner's program, which is auditable by the ERO, will ensure reliability. Extending the requirements to lines other than those >200KV may reduce the focus on those lines and may cause the allocation of resources away from lines >200KV. Generally easements are narrower on lower voltage lines, requiring more resources and emphasis on these lines. This may have an effect on the ability to focus clearing efforts on those lines that will have a much greater impact on the bulk power system. The IEEE standard when used as the minimum clearance distance at maximum operating condition will ensure reliability when these clearances are maintained by vegetation management activities. In addition, we do not agree that a standard of zero tolerance for vegetaion-related outages in the ROW is weak on compliance.

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: Minimum Inspection Intervals:
   The SERC VMS believes that FAC 003-1 provides the proper amount of flexibility regarding vegetation inspection cycles and that the Standards Drafting Team should not impose minimum inspection intervals on a continent with such regional diversity in climate and plant life.

   The purpose of Requirement 1.1 of standard FAC-003-1 is to put the responsibility for proper inspection cycles on the entity that knows the local conditions and can best define what that inspection frequency should be, the Transmission Owner. Both NERC and the FERC staff have recognized that various local conditions can have an affect on the determination of adequate inspection frequencies. Establishing a mandatory minimum inspection frequency could have two detrimental effects on the industry.

   First, where a particular region is heavily forested and has heavy rainfall along with extended or year round growing seasons, a "back stop" minimum inspection frequency could lead transmission owners to conduct inspections less frequently than required by the local conditions. This could result in a Transmission Owner complying with the standard while not adequately protecting the reliability of that region's transmission system. This is a "lowest common denominator" approach which FERC has repeatedly stated is inappropriate for the reliability standards.

Second, where a particular region is arid, sparsely forested or has a minimum growing season, a "back stop" minimum could require a more frequent interval than is realistically needed. This would result in increased and unnecessary costs for electric utility customers without providing an increase in system reliability.

In its discussion of inspection intervals, FERC indicates that a "one-year vegetation inspection cycle is reasonable." FERC NOPR, 10/20/2002 paragraph 383. The Commission continues by stating "a one-year inspection cycle is the 'norm' for the industry, but not the lowest common denominator…" It follows from this observation that the industry as a whole recognizes and follows appropriate inspection intervals without a need to change the standard. Further, FERC also states "some variation to a continent-wide, one-year minimum inspection cycle should be allowed due to physical differences such as climate and species of vegetation." FERC NOPR 10/20/2006, paragraph 382. FERC's express recognition that a "one size fits all" approach is not appropriate further supports the SERC VMS's contention that the existing inspection requirements in standard FAC-003-1 should remain unchanged.

Finally, the performance metrics of FAC-003 require the reporting of applicable transmission interruptions that are caused by vegetation. This process should appropriately identify Transmission Owners' inspection cycles that are not adequate. In this event, the ERO has the authority to engage the Transmission Owner in enforcement compliance actions and, therefore, can remedy any vegetation-related outage that is attributed to the Transmission Owner's inspection frequency.

Standard Applicability:
The SERC VMS disagrees with the proposal to revise the 200 kV threshold for determining facilities subject to this standard.

The majority of transmission facilities below 200 kV have significantly different design/construction/operating characteristics and have not been cited as impacting bulk power system reliability. For example, the Final Report on the August 14, 2003 Blackout in the United states and Canada: Causes and Recommendations April 2004 by the U.S.-Canada Power System Outage Task Force and all referenced major blackouts(pages 103-115) in that report, cited only outages which involved vegetation at line voltages above 200 kV. Generally applying requirements appropriate for 200 kV lines to lines less than 200 kV will result in significant documentation and reporting of items such as restrictions, mitigation plans, off right-of-way vegetation-related outage investigation/information and other issues, all of which dilutes the focus on lines that directly impact bulk power system reliability.

Revising the standard to use general criteria or broad language for defining "Bulk Power System" transmission lines covered by the standard could become a "one size fits all" approach. If that approach were taken, the standard would cover a significant number of transmission lines that have no direct impact on bulk power system reliability under standard planning/operating conditions, resulting in a significant increase in costs for electric customers without improving "Bulk Power System" system reliability. The SERC VMS believes that the applicability provision of the standard should instead focus attention of the standard only on the transmission lines below 200 kV that directly impact "Bulk Power System" reliability, as the current version requires.

In sum, while the SERC VMS recognizes some validity in the Commission's concern, the SERC VMS recommends that the applicability provision of this standard should be revised only if existing system design, planning or operating reliability criteria and parameters are considered as a basis for defining the applicability of the standard. To that end, the SERC VMS recommends each Regional Entity (RE) determine applicability of FAC-003 to those lines within the region that are between 100 kV and 200 KV if and only if they are identified as operationally significant elements of Interconnection Reliability Operating Limits ("IROLs").

IEEE Standard for Minimum Clearances:
The SERC VMS disagrees with objections in the FERC staff report to the use of the IEEE 516-2003 clearance as the minimum acceptable distances for "Clearance 2". The IEEE 516-2003 tables are appropriate for defining the minimum acceptable clearances to prevent flashover between conductors and vegetation under all rated electrical operating conditions. Closer minimum clearances such as the minimum length of a support insulator could have been adopted as a "lowest common denominator" clearance. However the clearance in IEEE 516-2003 was adopted to ensure an additional margin of reliability. FERC staff references ANSI Z-133 which is a safety standard that addresses worker safety as well as the safety of the general public. As such, the purpose of ANSI Z-133 is to address worker safety and is not focused on transmission line reliability, which is the purpose of FAC-003-1. OSHA, NESC and other related safety standards have clearances in excess of IEEE 516-2003. Those clearances are clearly focused on safety issues and will still apply to other aspects of design and operation of electric facilities (such as public and worker safety) but do not need to be referenced in a vegetation management reliability standard.

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

☒ Yes

☐ No

Comments: Standard Applicability:
The outage reporting requirement for the RRO should be deleted. Making FAC-003 applicable to the RRO is in violation of the legislation that established the ERO. This legislation states that enforceable standards can apply only to owners, users and operators of the bulk power system. Futher, in the NOPR on NERC standards, FERC declined to approve those standards that applied to the RROs, in part because the RROs are not owners, users or operators.

Compliance:
The SERC VMS recommends deleting reporting requirements for Category 3 outages. These outages are not controllable, not relevant to compliance, not related to grid reliability, not related to cascading blackouts, and such reporting leads to unnecessarily biasing reliability related information.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Brian Thumm	
Organization:	ITC Transmission	
Telephone:	248.374.7846	
E-mail:	bthumm@itctransco.com	

NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs,
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
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☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations, Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

FAC-003-1 is a relatively new standard that was approved in 2006. FAC-003 has some "fill-in-the-blank" components to eliminate. In addition, the following comments submitted by FERC and stakeholders need to be addressed in the refinement of the standard:

FERC NOPR

- Develop a minimum vegetation inspection cycle that allows variation for physical differences, as discussed above; and
- Remove the applicability to transmission lines operated at 200 kV and above so that the Reliability Standard applies to bulk power system transmission lines that have an impact of reliability as determined by the ERO.

FERC staff report

- Objections to use of IEEE standard

Stakeholder Comments

- Reliability Coordinator vs. Regional Reliability Organization
- Too weak on compliance
- Format inconsistencies

The improvements to the standard should bring the standard's format and elements into conformance with the latest version of the *Reliability Standards Development Procedure* and the ERO Rules of Procedure.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: While there may be "statutory" needs to address (e.g., FERC's request to modify particular components of the existing Standard), we do not feel there is a reliability need to do so.

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: The Standard Drafting Team should not be given lattitude to "include other improvements to the standards deemed appropriate by the drafting team." The purpose of the SAR is to identify the changes contemplated by the need for the Standard Revision. If there are changes that the SAR requestor would like to make to the Standard, they should be spelled out in the SAR. If the SAR requestor does not really know the changes that should be made to the standard, then the SAR should be withdrawn until the need for a SAR can be adequately justified.

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

   ☐ Yes

   ☒ No

   Comments: We think the Standard is fine the way it is.

Comment Form — 1st Posting of SAR for Revisions to Vegetation Management FAC-003-1

Please use this form to submit comments on the Vegetation Management SAR. Comments must be submitted by **February 14, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Vegetation Management" in the subject line. If you have questions, please contact Richard Schneider at richard.schneider@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs,
☐ **MRO**	☐	3 — Load-serving Entities
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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations, Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: ISO RTO Council Standards Review Committee

Lead Contact: **Charles Yeung**

Contact Organization: **Southwest Power Pool**

Contact Segment: **2**

Contact Telephone: **832-724-6142**

Contact E-mail: **cyeung@spp.org**

Additional Member Name	Additional Member Organization	Region*	Segment*
Tom Bowe	PJM	RFC	2
Mike Calimano	NYISO	NPCC	2
Ron Falsetti	IESO	NPCC	2
Matt Goldberg	ISO-NE	NPCC	2
Brent Kingsford	CAISO	WECC	2
Anita Lee	AESO	WECC	2
Steve Myers	ERCOT	ERCOT	2
Bill Phillips	MISO	RFC	2
		SERC	
		MRO	

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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FERC NOPR

- Develop a minimum vegetation inspection cycle that allows variation for physical differences, as discussed above; and
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FERC staff report

- Objections to use of IEEE standard

Stakeholder Comments

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- Too weak on compliance
- Format inconsistencies

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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: The SRC would suggest that the SAR be clear that it will be a complete review of the subject requirements: to include the addition, deletion and modification of requirements as agreed to by public consensus.

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

   ☐ Yes

   ☒ No

   Comments:

Please use this form to submit comments on the Vegetation Management SAR. Comments must be submitted by **February 14, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Vegetation Management" in the subject line. If you have questions, please contact Richard Schneider at richard.schneider@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	James H. Sorrels, Jr.	
Organization:	American Electric Power	
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E-mail:	jhsorrels@AEP.com	
NERC Region		**Registered Ballot Body Segment**
☒ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs,
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
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	☐	10 — Regional Reliability Organizations, Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

FAC-003-1 is a relatively new standard that was approved in 2006. FAC-003 has some “fill-in-the-blank” components to eliminate. In addition, the following comments submitted by FERC and stakeholders need to be addressed in the refinement of the standard:

FERC NOPR

- Develop a minimum vegetation inspection cycle that allows variation for physical differences, as discussed above; and
- Remove the applicability to transmission lines operated at 200 kV and above so that the Reliability Standard applies to bulk power system transmission lines that have an impact of reliability as determined by the ERO.

FERC staff report

- Objections to use of IEEE standard

Stakeholder Comments

- Reliability Coordinator vs. Regional Reliability Organization
- Too weak on compliance
- Format inconsistencies

The improvements to the standard should bring the standard’s format and elements into conformance with the latest version of the *Reliability Standards Development Procedure* and the ERO Rules of Procedure.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: American Electric Power believes that the current standard (when thoroughly read and understood) is completely adequate to maintain a reliable transmission system with minimum risk of vegetation-related outages.

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: American Electric Power is not aware of any evidence to support a need for revising the vegetation management standard.

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

   ☐ Yes

   ☒ No

   Comments: As stated in responses to questions 1 and 2, AEP believes that the current standard is adequate and that we are not aware of evidence to support a need for revising the current vegetation management standard.

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	John R. Kellum, Jr.	
Organization:	CenterPoint Energy Houston Electric, LLP	
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E-mail:	john.kellum@centerpointenergy.com	
NERC Region		**Registered Ballot Body Segment**
☒ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs,
☐ **MRO**	☐	3 — Load-serving Entities
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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

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FERC NOPR

- Develop a minimum vegetation inspection cycle that allows variation for physical differences, as discussed above; and
- Remove the applicability to transmission lines operated at 200 kV and above so that the Reliability Standard applies to bulk power system transmission lines that have an impact of reliability as determined by the ERO.

FERC staff report

- Objections to use of IEEE standard

Stakeholder Comments

- Reliability Coordinator vs. Regional Reliability Organization
- Too weak on compliance
- Format inconsistencies

The improvements to the standard should bring the standard's format and elements into conformance with the latest version of the *Reliability Standards Development Procedure* and the ERO Rules of Procedure.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: CenterPoint Energy disagrees that there is a reliability-related need to address the proposed revisions to FAC-003-1.

   This SAR proposes to establish a minimum vegetation inspection cycle for transmission facilities throughout the United States. Yet, based upon the location of each utility, different vegetation and growth rates will be experienced throughout the country. Placing a time specific vegetation management cycle for all regions does not address the wide divergence of vegetation and growth rates that each utility must face.

   For instance, in certain areas of the country, such as desert areas, vegetation growth rates are exceedingly small; therefore, vegetation management cycles would likely be for extended periods of time. Placing a required frequent cycle will unnecessarily increase the costs to ratepayers. While in other parts of the country, vegetation can grow rapidly, and there should be shorter periods of time for the vegetation management cycle.

   Based upon these facts, CenterPoint Energy does not believe that adopting a standard inspection cycle that is applicable to all regions is prudent. However, CenterPoint Energy understands and supports the concept of standard requirements applicable to all regions where such standardization is practical and reasonable. In the specific case of vegetation management, it may be reasonable and practical to establish a national standard based on maximum number of allowed annual vegetation-caused outages per 100-circuit-miles of transmission. Such a standard would allow utilities flexibility to use inspection cycles and other practices that are prudent based on each utility's circumstances while still holding utilities accountable for the results.

   The SAR also proposes to change the 200 kV threshold and use of the IEEE standard for minimum clearances. These requirements were established by a broad consensus of industry experts. CenterPoint Energy believes the broad industry consensus on these matters should be respected.

   CenterPoint Energy submits the following specific comments:

   Minimum inspection cycle, FERC NOPR Paragraph 382-

   CenterPoint Energy disagrees that "complete discretion left to the transmission owners in determining inspection cycles limits the effectiveness of the Reliability Standard." The standard is effective because it requires the transmission owners to balance several factors to achieve the optimum inspection cycle.

It is not necessary to specify a specific inspection interval in the standard. The inspection cycle interval is one component of several conditions to be considered in FAC-003-1 Requirement R1.2.1 for establishing the required Clearance 1 of the NERC standard. Other conditions that should be considered include operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. It is the growth rate of the vegetation coupled with the amount of clearance achieved at the time of maintenance that determines the inspection cycle interval. As such, the longer the inspection interval, the larger the clearance that must attained to achieve balance. If the utility does not achieve balance, then it will likely not avoid vegetation-related outages. It would not be necessary for a utility to be faulted based on its inspection interval, rather it would be measured for compliance under FAC-003-1 D2.3.1, D2.3.2, D2.3.3, and D2.4.1 for operational conditions regarding maintaining the minimum clearance (Clearance 2) required under FAC-003-1 Requirement R1.2.2 and any actual vegetation-related outages.

FERC NOPR Paragraph 383-

CenterPoint Energy disagrees that "a one-year vegetation inspection cycle is the "norm" for the industry." The reference to "76 of 161 entities surveyed conduct ground inspections once a year" was taken from Table 3 entitled "Ground Inspection Frequency". The table can also be interpreted to indicate that 78 of 161 entities surveyed conduct ground inspections on cycles other than once a year. At best, the table shows a distribution of the varying practices of companies surveyed. The table by itself does not indicate the level of reliability provided by each of those companies.

The table entries may also be incomplete because the original order under Docket EL04-52-000 under paragraph 12c asked "how often the transmission provider inspects that facility for vegetation management purposes" which did not specify ground or aerial inspection. The EEI template that many respondents used did specify ground inspection and aerial inspection separately, but the template was not used by all of the respondents as noted in the report. Interpolation of the data collected may have affected the accuracy of the results reported, so specific conclusions should consider the disparity between how the data request was worded and how the data was reported. It is important to clearly distinguish between ground inspection, aerial inspection, and pruning cycle when soliciting and interpreting industry data. Additionally, new technologies such as airborne laser surveys are coming to the market which may replace or augment other types of vegetation inspections as they become cost-effective. The industry "norm" may change as a result.

FERC NOPR Paragraph 384-

Although CenterPoint Energy does not agree with establishing a "one year minimum inspection cycle", it should be left to the discretion of the transmission owner as to what type of inspection is employed so that the most cost-effective methods can be utilized, depending on the system's size and terrain. It should also be made clear that "inspection cycle" is not intended to mean "pruning cycle".

Remove 200kV threshold, FERC NOPR Paragraph 385-

CenterPoint Energy believes the applicability of FAC-003-1 should be "to all transmission lines operated at 200kV and above and to any lower voltage lines designated by the regional reliability organization as critical to reliability", because such a standard most closely matches the vegetation management reporting requirements from Docket EL04-52-000. Voltages below this threshold are not likely to impact the reliability of the Bulk Power System. Further, regional reliability organizations have the authority to designate lower voltages critical to reliability as appropriate. The proposed change is unnecessary.

IEEE Standard as basis for minimum clearance to prevent flashover (Clearance 2) -

CenterPoint Energy believes that the IEEE standard is sufficient and appropriate as a basis to determine the specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions (Clearance 2). Clearance 2 also must consider additional clearance for the dynamic movement of the transmission conductors to avoid vegetation related outages. Thus, the minimum clearances that a transmission owner must identify and document depend on a variety of conditions including, but not limited to, transmisison line voltage, temperature, wind velocities, and altitude.

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

☐ Yes

☒ No

Comments: CenterPoint Energy does not agree with the scope of the SAR for the reasons discussed in response to question 1.

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

☐ Yes

☒ No

Comments:

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Kathleen Goodman	
Organization:	ISO New England	
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E-mail:	kgoodman@iso-ne.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
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FERC staff report

- Objections to use of IEEE standard

Stakeholder Comments

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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: ISO New England would suggest that the SAR be clear that it will be a complete review of the subject requirements: to include the addition, deletion and modification of requirements as agreed to by public consensus.

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

   ☐ Yes

   ☒ No

   Comments:

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Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs,
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations, Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: Public Service Commission of South Carolina

Lead Contact: **Phil Riley**

Contact Organization: **Public Service Commission of South Carolina**

Contact Segment: **9**

Contact Telephone: **803-896-5154**

Contact E-mail: **philip.riley@psc.sc.gov**

Additional Member Name	Additional Member Organization	Region*	Segment*
Mignon L. Clyburn	Public Service Commission of SC	SERC	9
Elizabeth B. Fleming	Public Service Commission of SC	SERC	9
G. O'Neal Hamilton	Public Service Commission of SC	SERC	9
John E. Howard	Public Service Commission of SC	SERC	9
Randy Mitchell	Public Service Commission of SC	SERC	9
C. Robert Moseley	Public Service Commission of SC	SERC	9
David A. Wright	Public Service Commission of SC	SERC	9

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

FAC-003-1 is a relatively new standard that was approved in 2006. FAC-003 has some "fill-in-the-blank" components to eliminate. In addition, the following comments submitted by FERC and stakeholders need to be addressed in the refinement of the standard:

FERC NOPR

- Develop a minimum vegetation inspection cycle that allows variation for physical differences, as discussed above; and
- Remove the applicability to transmission lines operated at 200 kV and above so that the Reliability Standard applies to bulk power system transmission lines that have an impact of reliability as determined by the ERO.

FERC staff report

- Objections to use of IEEE standard

Stakeholder Comments

- Reliability Coordinator vs. Regional Reliability Organization
- Too weak on compliance
- Format inconsistencies

The improvements to the standard should bring the standard's format and elements into conformance with the latest version of the *Reliability Standards Development Procedure* and the ERO Rules of Procedure.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: We are concerned that lowering the applicability threshold to all lines below 200KV will divert attention and resources from the higher voltage lines which have a higher probability of causing grid problems. The RRO and transmission owners best know which lower voltage lines should be included under the requirements of the standard.

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

   ☐ Yes

   ☒ No

   Comments:

Comment Form — 1st Posting of SAR for Revisions to Vegetation Management FAC-003-1

Please use this form to submit comments on the Vegetation Management SAR. Comments must be submitted by **February 14, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Vegetation Management" in the subject line. If you have questions, please contact Richard Schneider at richard.schneider@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information		
(Complete this page for comments from one organization or individual.)		
Name: Robert Coish		
Organization: Manitoba Hydro		
Telephone: 204-487-5479		
E-mail: rgcoish@hydro.mb.ca		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs,
☒ **MRO**	☒	3 — Load-serving Entities
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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations, Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

FAC-003-1 is a relatively new standard that was approved in 2006. FAC-003 has some "fill-in-the-blank" components to eliminate. In addition, the following comments submitted by FERC and stakeholders need to be addressed in the refinement of the standard:

FERC NOPR

- Develop a minimum vegetation inspection cycle that allows variation for physical differences, as discussed above; and
- Remove the applicability to transmission lines operated at 200 kV and above so that the Reliability Standard applies to bulk power system transmission lines that have an impact of reliability as determined by the ERO.

FERC staff report

- Objections to use of IEEE standard

Stakeholder Comments

- Reliability Coordinator vs. Regional Reliability Organization
- Too weak on compliance
- Format inconsistencies

The improvements to the standard should bring the standard's format and elements into conformance with the latest version of the *Reliability Standards Development Procedure* and the ERO Rules of Procedure.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: The scope of the SAR is too vague on several important points. (1) There is no definition for the phrase bulk-power system - it would be therefore unclear as to what facilities would be covered by the standard. What guidance will the SDT have in determining what is meant by the bulk-power system? Since this relates to the large issue of the Bulk Electric System versus Bulk-Power System is this SAR the appropriate vehicle to address this issue? There should be a wider discussion and resolution to this issue for consistent application to all standards by all SDTs. (2)The concept of Mitigation Time Horizons has not been defined and the use of Mitigation Time Horizons has not been detailed. (3)The ERO is not the appropriate entity to determine which lines have an impact on reliability. This should be Transmission Operators in coordination with Reliability Coordinators. If this standard is to include the methodology to determine which lines have a reliability impact on the bulk-power system, the the applicability of the standard will have to include other entities besides the Transmission Owners. (4) The SAR refers to RA, i.e., Reliability Authority. This entity no longer exists in the Functional Model but has been replaced by Reliability Coordinator. (5) What is meant by "Too weak on compliance"? (5) FERC objects to IEEE Standard but there is no other guidance to the standard drafting team.

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

   ☐ Yes

   ☐ No

   Comments: None identified.

Please use this form to submit comments on the Vegetation Management SAR. Comments must be submitted by **February 14, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words “Vegetation Management” in the subject line. If you have questions, please contact Richard Schneider at richard.schneider@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information

(Complete this page for comments from one organization or individual.)

Name:	Roger Champagne
Organization:	Hydro-Québec TransÉnergie
Telephone:	514 289-2211; X 2766
E-mail:	champagne.roger.2@hydro.qc.ca

NERC Region		Registered Ballot Body Segment
☐ ERCOT	☒	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs, ISOs,
☐ MRO	☐	3 — Load-serving Entities
☒ NPCC	☐	4 — Transmission-dependent Utilities
☐ RFC	☐	5 — Electric Generators
☐ SERC	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ SPP	☐	7 — Large Electricity End Users
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☐ NA – Not Applicable	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations, Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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Stakeholder Comments

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- Format inconsistencies

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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: We believe that it is premature to move forward with changes based on voltage class. Applicability of the standard should only be to those portions of the system that are part of the Bulk Power System which have been determined by a performance based methodology.

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☒ Yes

   ☒ No

   Comments: FERC staff report has objection to use IEEE standard. Should we understand that another standard is recommended instead?

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

   ☐ Yes

   ☒ No

   Comments:

Please use this form to submit comments on the Vegetation Management SAR. Comments must be submitted by **February 14, 2007.** You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Vegetation Management" in the subject line. If you have questions, please contact Richard Schneider at richard.schneider@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs, ISOs,
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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations, Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: South Carolina Electric & Gas Company

Lead Contact: **Jerry Lindler**

Contact Organization: **Electric Transmission**

Contact Segment: **1**

Contact Telephone: **803-217-9135**

Contact E-mail: **jlindler@scana.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
Lee Xanthakos	**SCE&G**	**SERC**	1
Clay Young	**SCE&G**	**SERC**	3
Matt Hammond	**SCE&G**	**SERC**	6
Rick Jones	**SCE&G**	**SERC**	5

*If more than one region or segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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FERC staff report

- Objections to use of IEEE standard

Stakeholder Comments

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- Too weak on compliance
- Format inconsistencies

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The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

   ☒ Yes

   ☒ No

   Comments: SCE&G is unsure how to interpret the question but would like to offer the following comments:

   The current standard contains appropriate requirements and measures to ensure the owners vegetation management program is implemented and managed to ensure the reliability of the transmission system. Mandating inspection cycle frequencies will not enhance nor ensure reliability by inspecting more or less frequently. The minimum vegetation clearances at maximum operating conditions that are established within the owner's program, which is auditable by the ERO, will ensure reliability. Extending the requirements to lines other than those >200KV may reduce the focus on those lines and may cause the allocation of resources away from lines >200KV. Generally easements are narrower on lower voltage lines, requiring more resources and emphasis on these lines. This may have an effect on the ability to focus clearing efforts on those lines that will have a much greater impact on the bulk power system. The IEEE standard when used as the minimum clearance distance at maximum operating condition will ensure reliability when these clearances are maintained by vegetation management activities. In addition, we do not agree that a standard of zero tolerance for vegetaion-related outages in the ROW is weak on compliance.

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

   ☐ Yes

   ☒ No

   Comments: Minimum Inspection Intervals:
   SCE&G believes that FAC 003-1 provides the proper amount of flexibility regarding vegetation inspection cycles and that the Standards Drafting Team should not impose minimum inspection intervals on a continent with such regional diversity in climate and plant life.

   The purpose of Requirement 1.1 of standard FAC-003-1 is to put the responsibility for proper inspection cycles on the entity that knows the local conditions and can best define what that inspection frequency should be, the Transmission Owner. Both NERC and the FERC staff have recognized that various local conditions can have an affect on the determination of adequate inspection frequencies. Establishing a mandatory minimum inspection frequency could have two detrimental effects on the industry.

   First, where a particular region is heavily forested and has heavy rainfall along with extended or year round growing seasons, a “back stop” minimum inspection frequency could lead transmission owners to conduct inspections less frequently than required by the local conditions. This could result in a Transmission Owner complying with the standard while not adequately protecting the reliability of that region's transmission system. This is a "lowest common denominator" approach which FERC has repeatedly stated is inappropriate for the reliability standards.

Second, where a particular region is arid, sparsely forested or has a minimum growing season, a "back stop" minimum could require a more frequent interval than is realistically needed. This would result in increased and unnecessary costs for electric utility customers without providing an increase in system reliability.

In its discussion of inspection intervals, FERC indicates that a "one-year vegetation inspection cycle is reasonable." FERC NOPR, 10/20/2002 paragraph 383. The Commission continues by stating "a one-year inspection cycle is the 'norm' for the industry, but not the lowest common denominator…" It follows from this observation that the industry as a whole recognizes and follows appropriate inspection intervals without a need to change the standard. Further, FERC also states "some variation to a continent-wide, one-year minimum inspection cycle should be allowed due to physical differences such as climate and species of vegetation." FERC NOPR 10/20/2006, paragraph 382. FERC's express recognition that a "one size fits all" approach is not appropriate further supports the SERC VMS's contention that the existing inspection requirements in standard FAC-003-1 should remain unchanged.

Finally, the performance metrics of FAC-003 require the reporting of applicable transmission interruptions that are caused by vegetation. This process should appropriately identify Transmission Owners' inspection cycles that are not adequate. In this event, the ERO has the authority to engage the Transmission Owner in enforcement compliance actions and, therefore, can remedy any vegetation-related outage that is attributed to the Transmission Owner's inspection frequency.

Standard Applicability:
SCE&G disagrees with the proposal to revise the 200 kV threshold for determining facilities subject to this standard.

The majority of transmission facilities below 200 kV have significantly different design/construction/operating characteristics and have not been cited as impacting bulk power system reliability. For example, the Final Report on the August 14, 2003 Blackout in the United states and Canada: Causes and Recommendations April 2004 by the U.S.-Canada Power System Outage Task Force and all referenced major blackouts(pages 103-115) in that report, cited only outages which involved vegetation at line voltages above 200 kV. Generally applying requirements appropriate for 200 kV lines to lines less than 200 kV will result in significant documentation and reporting of items such as restrictions, mitigation plans, off right-of-way vegetation-related outage investigation/information and other issues, all of which dilutes the focus on lines that directly impact bulk power system reliability.

Revising the standard to use general criteria or broad language for defining "Bulk Power System" transmission lines covered by the standard could become a "one size fits all" approach. If that approach were taken, the standard would cover a significant number of transmission lines that have no direct impact on bulk power system reliability under standard planning/operating conditions, resulting in a significant increase in costs for electric customers without improving "Bulk Power System" system reliability. SCE&G believes that the applicability provision of the standard should instead focus attention of the standard only on the transmission lines below 200 kV that directly impact "Bulk Power System" reliability, as the current version requires.

In sum, while SCE&G recognizes some validity in the Commission's concern, we recommend that the applicability provision of this standard should be revised only if existing system design, planning or operating reliability criteria and parameters are considered as a basis for defining the applicability of the standard. To that end, we recommend that each Regional Entity (RE) determine applicability of FAC-003-1 to those lines within the region that are between 100 kV and 200 KV if and only if they are identified as operationally significant elements of Interconnection Reliability Operating Limits ("IROLs").

IEEE Standard for Minimum Clearances:
SCE&G disagrees with objections in the FERC staff report to the use of the IEEE 516-2003 clearance as the minimum acceptable distances for "Clearance 2". The IEEE 516-2003 tables are appropriate for defining the minimum acceptable clearances to prevent flashover between conductors and vegetation under all rated electrical operating conditions. Closer minimum clearances such as the minimum length of a support insulator could have been adopted as a "lowest common denominator" clearance. However the clearance in IEEE 516-2003 was adopted to ensure an additional margin of reliability. FERC staff references ANSI Z-133 which is a safety standard that addresses worker safety as well as the safety of the general public. As such, the purpose of ANSI Z-133 is to address worker safety and is not focused on transmission line reliability, which is the purpose of FAC-003-1. OSHA, NESC and other related safety standards have clearances in excess of IEEE 516-2003. Those clearances are clearly focused on safety issues and will still apply to other aspects of design and operation of electric facilities (such as public and worker safety) but do not need to be referenced in a vegetation management reliability standard.

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

☒ Yes

☐ No

Comments: Compliance:
The SERC VMS recommends deleting reporting requirements for Category 3 outages. These outages are not controllable, not relevant to compliance, not related to grid reliability, not related to cascading blackouts, and such reporting leads to unnecessarily biasing reliability related information.

The Transmission Vegetation Management SAR Drafting Team thanks all commenters who submitted comments on the first draft of the Transmission Vegetation Management SAR. This SAR was posted for a 30 day public comment period from January 15–February 14, 2007. The Standards Committee asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 19 sets of comments, including comments from more than 80 different people from more than 63 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the drafting team revised the SAR to reflect these comments and improvements identified by the FERC in its Mandatory Reliability Standards for the Bulk Power System Order 693.

The following major changes were made to the SAR:

- Updated the Purpose to use language that matches the associated standard (e.g., where FAC-003 is only related to the transmission system, the term, 'bulk power system' was replaced with 'transmission system').
- Added the items NERC is required to address in compliance with FERC Order 693
- Added the following items to the list of items to review in refining the standard:
  - Review reporting criteria for Category 3 outages in the proposed technical reference material and may remove the reporting requirement of Category 3 outages in R.3 and R.4.
  - Consider deleting requirement R.4.
  - Review the reporting exemptions to include all category outages under major disasters in Requirement R3.2.
- Added a commitment to prepare a technical reference such as a "white paper" to aid in understanding the technical basis for the standard.
- The descriptions of the 'Reliability Functions' on page 3 of the SAR were updated to reflect Version 3 of the Functional Model.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Vegetation-Management_Project_2007-7.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Anita Lee (G2)	AESO		✓								
2.	Jay Farrington (G6)	Alabama Electric Coop	✓									
3.	Randall Gann (G6)	Alabama Power Co.	✓									
4.	William J. Smith	Allegheny Power	✓									
5.	Ken Goldsmith (G3)	ALT										✓
6.	Raymond Wiesehan (G6)	Ameren	✓									
7.	James H. Sorrels, Jr.	American Electric Power	✓				✓	✓				
8.	John Neagle (G6)	Associate Electric Coop	✓									
9.	William T. Rees	Baltimore Gas and Electric	✓									
10.	Brian Bartos	Bandera Electric Coop., Inc.										
11.	Michael D. Johnson	Bonneville Power Administration	✓									
12.	Dave Rudolph (G3)	BPEC										✓
13.	Brent Kingsford (G2)	CAISO		✓								
14.	John R. Kellum, Jr.	CenterPoint Energy Houston Electric, LLP	✓									
15.	Michael Spector	Central Hudson Gas & Electric	✓		✓							
16.	Alan Gale (G1)	City of Tallahassee					✓					
17.	Ed Thompson (G4)	ConEd	✓									
18.	John Loftis	Dominion - Electric Transmission	✓									
19.	Billy George (G6)	Duke Energy Carolinas	✓									
20.	Ralph Hale (G6)	Entergy	✓									
21.	Steve Myers (G2)	ERCOT		✓								
22.	Marc Tunstall (G6)	Fayetteville PWC	✓									
23.	Pedro Modia (G1)	Florida Power and Light Company	✓									
24.	Barbara Jaindl	Florida Power and Light Company	✓									
25.	Greg Keller	Florida Power and Light Company	✓									
26.	John Tamsberg	Florida Power and Light Company	✓									
27.	Marty Mennes	Florida Power and Light Company	✓									
28.	Michael Warr	Florida Power and Light Company	✓									
29.	Eric Senkowicz (G1)	FRCC										✓
30.	Mark Bennett (G1)	Gainesville Regional Utilities					✓					
31.	John West (G6)	Georgia Power Co.	✓									
32.	Jimmy Etheridge (G6)	Georgia Transmission Corporation	✓									
33.	Steve Burns (G6)	Gulf Power Co.	✓									
34.	David Kiguel (G4) (I)	Hydro One Networks, Inc.	✓									
35.	George Juhn	Hydro One Networks, Inc.	✓									
36.	Roger Champagne (G4) (I)	Hydro-Québec TransÉnergie	✓									
37.	Ron Falsetti (G2) (G4) (I)	IESO Ontario		✓								
38.	Bill Shemley (G4)	ISO-NE		✓								

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
39.	Kathleen Goodman (G4) (I)	ISO-NE		✓								
40.	Matt Goldberg (G2)	ISO-NE		✓								
41.	Brian Thumm	ITC Transmission	✓									
42.	Clark Hawkins (G1)	Lee County Electric Cooperative			✓							
43.	Eric Ruskamp (G3)	LES										✓
44.	Don Nelson (G4)	MA Dept. of Tele. and Energy									✓	
45.	Robert Coish (G3) (I)	Manitoba Hydro	✓		✓		✓	✓				
46.	Tom Mielnik (G3)	MEC										✓
47.	Dick Pursley (G3)	Midwest Reliability Organization										✓
48.	Bill Phillips (G2)	MISO		✓								
49.	Terry Bilke (G3)	MISO										✓
50.	Carol Gerou (G3)	MP										✓
51.	Joe Knight (G3)	MRO										✓
52.	Richard Mider	New York State Electric and Gas Corporation	✓									
53.	Herb Schrayshuen (G4)	NGRID	✓									
54.	Murale Gopinathan (G4)	Northeast Utilities	✓									
55.	Brian Hogue (G4)	NPCC										✓
56.	Guy V. Zito (G4)	NPCC										✓
57.	Alan Boesch (G3)	NPPD										✓
58.	Jerad Barnhart (G4)	NSTAR	✓									
59.	Greg Campoli (G4)	NYISO		✓								
60.	Mike Calimano (G2)	NYISO		✓								
61.	Ralph Rufrano (G4)	NYPA	✓									
62.	Todd Gosnell (G3)	OPPD										✓
63.	Tom Bowe (G2)	PJM		✓								
64.	Jack Gardner (G6) (I)	Progress Energy Carolinas	✓									
65.	C. Robert Moseley (G5)	Public Service Commission of SC									✓	
66.	David A. Wright (G5)	Public Service Commission of SC									✓	
67.	Elizabeth B. Fleming (G5)	Public Service Commission of SC									✓	
68.	G. O'Neal Hamilton (G5)	Public Service Commission of SC									✓	
69.	John E. Howard (G5)	Public Service Commission of SC									✓	
70.	Mignon L. Clyburn (G5)	Public Service Commission of SC									✓	
71.	Phil Riley (G5)	Public Service Commission of SC									✓	
72.	Randy Mitchell (G5)	Public Service Commission of SC									✓	
73.	Mike Gentry	Salt River Project	✓									
74.	Jerry Lindler (G6)	SCE&G	✓									
75.	John Wolfmeyer (G6)	SERC Vegetation Management Subcommittee										
76.	Sam Stonerock	Southern California Edison	✓									
77.	Jim Busbin (G7)	Southern Company Transmission	✓									

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
78.	JT Wood (G7)	Southern Company Transmission	✓									
79.	Marc Butts (G7)	Southern Company Transmission	✓									
80.	Roman Carter	Southern Company Transmission	✓									
81.	Charles Yeung (G2)	SPP		✓								
82.	Richard Dearman (G6) (I)	TVA	✓									
83.	Jim Haigh (G3)	WAPA										✓
84.	Neal Balu (G3)	WPSR										✓
85.	Pam Oreschnick (G3)	XEL										✓

G1 – FRCC

G2 - ISO/RTO Council Standards Review Committee

G3 - Midwest Reliability Organization

G4 - NPCC CP9 - Reliability Standards Working Group

G5 – Public Service Commission of South Carolina

G6 - SERC Vegetation Management Subcommittee

G7 – Southern Company Transmission

I – Individual comments were submitted in addition to comments as part of a group

Index to Questions, Comments, and Responses

1. Do you agree that there is a reliability-related need to address the proposed revisions to FAC-003-1 — Transmission Vegetation Management? If not, please explain in the comment area.

Summary Consideration: Most commenters indicated that they do not believe there is a reliability need to revise the technical aspects of this standard. The SAR Drafting Team agrees with commenters who indicated that the original was SAR vague, and the drafting team modified the SAR to clarify that the proposed changes to this standard will address procedural updates to bring the standard into conformance with the latest version of NERC's Reliability Standards Development Procedure and the Sanctions Guidelines in the ERO Rules of Procedure, and will also address the issues raised in the FERC's March 16, 2007 Order 693 - Mandatory Reliability Standards for the Bulk Power System.

<table>
<tr><th colspan="4">Question #1</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td>Bonneville Power Administration</td><td></td><td>☑</td><td>Ok, Yes and No. The first FERC NOPR bullet needs to be addressed.
The second bullet is clearly discribed in the standard. A. 4.4.3. The reader must read the statement in context. It meets the Standard Review Guidelines.</td></tr>
<tr><td colspan="4">Response:
▪ The FERC is no longer indicating a need to develop a requirement for a minimum inspection cycle (March 16, 2007 Order 693) and stakeholders indicated they did not support this change, so it was removed from the SAR.
▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to <200kV is necessary.
▪ The Drafting Team does not agree that the Standard Review Guidelines have been met. For example the guidelines calls for 'time horizons' to be assigned to each requirement, and the standard currently does not have these. The standard also needs to replace its 'levels of non-compliance' with 'violation severity levels' to support the latest version of the Sanctions Guidelines.</td></tr>
<tr><td>Bandera Electric Coop.</td><td></td><td>☑</td><td>The items listed as potential revisions are vague and do not provide sufficient justification to alter the current requirements of this standard which has been in effect less than 1 year. The current standard allows for the region to determine which transmission lines are critical to reliability and should be included in a Transmission Owner's Transmission Vegetation Management Plan regardless of voltage classification. The current standard also allows each TO the flexibility to develop its plan in accordance with its specific geography and operating environment. There is no need to be more prescriptive.</td></tr>
<tr><td colspan="4">Response:
▪ The Drafting Team agrees that the first SAR draft was vague. The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes:
o Re-format FAC-003-1 to conform to current Standards Development Procedure.
o Remove references to RRO in the standard and substitute a responsible entity.
o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels.
▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to <200kV is necessary.
▪ The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability</td></tr>
</table>

Question #1			
Commenter	**Yes**	**No**	**Comment**
Standards for the Bulk Power System.			
ITC Transmission		☑	While there may be "statutory" needs to address (e.g., FERC's request to modify particular components of the existing Standard), we do not feel there is a reliability need to do so.
Response: ▪ The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes: o Re-format FAC-003-1 to conform to the current Standards Development Procedure. o Remove references to RRO in the standard and substitute a responsible entity. o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels. ▪ The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.			
Hydro One Networks, Inc.		☑	We believe that at this time it is premature to move forward with changes to the standard that are based on voltage class issues. The Standard, as developed, applies to the BES which have been determined by a performance based methodology. NERC should wait until the BES vs. BPS issue is resolved.
Response: ▪ The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes: o Re-format FAC-003-1 to conform to the current Standards Development Procedure. o Remove references to RRO in the standard and substitute a responsible entity. o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels.			
Hydro-Québec TransÉnergie		☑	We believe that it is premature to move forward with changes based on voltage class. Applicability of the standard should only be to those portions of the system that are part of the Bulk Power System which have been determined by a performance based methodology.
Response: ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to <200kV is necessary.			
Northeast Power Coordinating Council		☑	NPCC participating members believe that it is premature to move forward with changes based on voltage class. Applicability of the standard should only be to those portions of the system that are part of the Bulk Power System which have been determined by a performance based methodology.
Response: ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to <200kV is necessary.			
American Electric Power		☑	American Electric Power believes that the current standard (when thoroughly read and understood) is completely adequate to maintain a reliable transmission system with minimum risk of vegetation-related outages.

Question #1			
Commenter	**Yes**	**No**	**Comment**
Response: ▪ The Drafting Team believes a revised standard is justified because it needs to include the following NEW procedural changes: o Re-format FAC-003-1 to conform to the current Standards Development Procedure. o Remove references to RRO in the standard and substitute a responsible entity. o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels. ▪ The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.			
New York State Electric and Gas Corporation		☑	The current draft FAC 003 1 will provide a high level of reliability for the transmission bulk delivery system which the public now expects. After a comprehensive industry review which included industry balloting, the current Vegetation Management Standard 003 1 was approved in Feburary 2006 and several sections did not go in to effect for one year (2007). Sufficient time should be allowed so that impact of the current standard can be monitored. FAC 003 1 was designed to prevent cascading type outages and by establishing a standard for 200KV lines and above catastrophic type power outages will be eliminated. Lower volatge lines can be placed under this standard when the impact on the bulk delivery system requires tighter management as determined by local reliability organizations. Inspection cycles must be designed to meet regional needs based on local conditons, and the current standard provides this flexiblity.
Response: ▪ The Drafting Team believes a revised standard is justified because it needs to include the following NEW procedural changes: o Re-format FAC-003-1 to conform to the current Standards Development Procedure. o Remove references to RRO in the standard and substitute a responsible entity. o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels. ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to <200kV is necessary. ▪ The FERC is no longer indicating a need to develop a requirement for a minimum inspection cycle (March 16, 2007 Order 693) and stakeholders indicated they did not support this change, so it was removed from the SAR. ▪ The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.			
SERC Reliability Corporation	☑	☑	The SERC VMS is unsure how to answer the question as it is worded, but has the following comments on the SAR: The current standard contains appropriate requirements and measures to ensure the owners vegetation management program is implemented and managed to ensure the reliability of the transmission system. Mandating inspection cycle

Question #1			
Commenter	**Yes**	**No**	**Comment**
			frequencies will not enhance nor ensure reliability by inspecting more or less frequently. The minimum vegetation clearances at maximum operating conditions that are established within the owner's program, which is auditable by the ERO, will ensure reliability. Extending the requirements to lines other than those >200KV may reduce the focus on those lines and may cause the allocation of resources away from lines >200KV. Generally easements are narrower on lower voltage lines, requiring more resources and emphasis on these lines. This may have an effect on the ability to focus clearing efforts on those lines that will have a much greater impact on the bulk power system. The IEEE standard when used as the minimum clearance distance at maximum operating condition will ensure reliability when these clearances are maintained by vegetation management activities. In addition, we do not agree that a standard of zero tolerance for vegetaion-related outages in the ROW is weak on compliance.
Response: ▪ The FERC is no longer indicating a need to develop a requirement for a minimum inspection cycle (March 16, 2007 Order 693) and stakeholders indicated they did not support this change, so it was removed from the SAR. ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary. ▪ The Drafting Team agrees with the commenter and recognizes that the IEEE standard is applicable. ▪ The Drafting Team modified the SAR to eliminate the comment that the standard is weak on compliance as this comment was satisfied when Version 1 of the standard was developed. ▪ The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.			
Progress Energy		☑	The current standard contains appropriate levels of guidelines and penalties to ensure the owners vegetation management program is implemented and managed to ensure the reliability of the transmission system. Mandating inspection cycle frequencies will not enhance nor ensure reliability by inspecting more or less frequently. The minimum vegetation clearances at maximum operating conditions that are established within the owner's program that are auditable by the ERO will ensure reliability. By adding lines other than those >200KV may reduce the focus on those lines and impact the budget dollars allocated to focus on the lines >200KV. Generally easements are much more narrow on lower voltage lines, the impact on budget dollars would often require more emphasis on these lines. This may have an effect on the ability to focus clearing efforts on those lines that will have a much greater impact on the bulk power system. The IEEE standard when used as the minimum clearance distance at maximum operating condition will ensure reliability when these clearances are maintained by vegetation management activities.

Question #1			
Commenter	**Yes**	**No**	**Comment**
Response: ▪ The current version of the standard does not include 'time horizons' and uses 'levels of non-compliance' rather than 'violation severity levels' - 'time horizons' and 'violation severity levels' are needed to conform to the latest version of the Sanctions Guidelines included in the ERO Rules of Procedure. ▪ The FERC is no longer indicating a need to develop a requirement for a minimum inspection cycle (March 16, 2007 Order 693) and stakeholders indicated they did not support this change, so it was removed from the SAR. ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary. ▪ The Drafting Team agrees with the commenter and recognizes that the IEEE standard is applicable. ▪ The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.			
CenterPoint Energy Houston Electric, LLP		☑	CenterPoint Energy disagrees that there is a reliability-related need to address the proposed revisions to FAC-003-1. This SAR proposes to establish a minimum vegetation inspection cycle for transmission facilities throughout the United States. Yet, based upon the location of each utility, different vegetation and growth rates will be experienced throughout the country. Placing a time specific vegetation management cycle for all regions does not address the wide divergence of vegetation and growth rates that each utility must face. For instance, in certain areas of the country, such as desert areas, vegetation growth rates are exceedingly small; therefore, vegetation management cycles would likely be for extended periods of time. Placing a required frequent cycle will unnecessarily increase the costs to ratepayers. While in other parts of the country, vegetation can grow rapidly, and there should be shorter periods of time for the vegetation management cycle. Based upon these facts, CenterPoint Energy does not believe that adopting a standard inspection cycle that is applicable to all regions is prudent. However, CenterPoint Energy understands and supports the concept of standard requirements applicable to all regions where such standardization is practical and reasonable. In the specific case of vegetation management, it may be reasonable and practical to establish a national standard based on maximum number of allowed annual vegetation-caused outages per 100-circuit-miles of transmission. Such a standard would allow utilities flexibility to use inspection cycles and other practices that are prudent based on each utility's circumstances while still holding utilities accountable for the results.

Question #1			
Commenter	Yes	No	Comment
			The SAR also proposes to change the 200 kV threshold and use of the IEEE standard for minimum clearances. These requirements were established by a broad consensus of industry experts. CenterPoint Energy believes the broad industry consensus on these matters should be respected. CenterPoint Energy submits the following specific comments: Minimum inspection cycle, FERC NOPR Paragraph 382- CenterPoint Energy disagrees that "complete discretion left to the transmission owners in determining inspection cycles limits the effectiveness of the Reliability Standard." The standard is effective because it requires the transmission owners to balance several factors to achieve the optimum inspection cycle. It is not necessary to specify a specific inspection interval in the standard. The inspection cycle interval is one component of several conditions to be considered in FAC-003-1 Requirement R1.2.1 for establishing the required Clearance 1 of the NERC standard. Other conditions that should be considered include operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. It is the growth rate of the vegetation coupled with the amount of clearance achieved at the time of maintenance that determines the inspection cycle interval. As such, the longer the inspection interval, the larger the clearance that must attained to achieve balance. If the utility does not achieve balance, then it will likely not avoid vegetation-related outages. It would not be necessary for a utility to be faulted based on its inspection interval, rather it would be measured for compliance under FAC-003-1 D2.3.1, D2.3.2, D2.3.3, and D2.4.1 for operational conditions regarding maintaining the minimum clearance (Clearance 2) required under FAC-003-1 Requirement R1.2.2 and any actual vegetation-related outages. FERC NOPR Paragraph 383-

Question #1			
Commenter	**Yes**	**No**	**Comment**
			CenterPoint Energy disagrees that "a one-year vegetation inspection cycle is the "norm" for the industry." The reference to "76 of 161 entities surveyed conduct ground inspections once a year" was taken from Table 3 entitled "Ground Inspection Frequency". The table can also be interpreted to indicate that 78 of 161 entities surveyed conduct ground inspections on cycles other than once a year. At best, the table shows a distribution of the varying practices of companies surveyed. The table by itself does not indicate the level of reliability provided by each of those companies. The table entries may also be incomplete because the original order under Docket EL04-52-000 under paragraph 12c asked "how often the transmission provider inspects that facility for vegetation management purposes" which did not specify ground or aerial inspection. The EEI template that many respondents used did specify ground inspection and aerial inspection separately, but the template was not used by all of the respondents as noted in the report. Interpolation of the data collected may have affected the accuracy of the results reported, so specific conclusions should consider the disparity between how the data request was worded and how the data was reported. It is important to clearly distinguish between ground inspection, aerial inspection, and pruning cycle when soliciting and interpreting industry data. Additionally, new technologies such as airborne laser surveys are coming to the market which may replace or augment other types of vegetation inspections as they become cost-effective. The industry "norm" may change as a result. FERC NOPR Paragraph 384- Although CenterPoint Energy does not agree with establishing a "one year minimum inspection cycle", it should be left to the discretion of the transmission owner as to what type of inspection is employed so that the most cost-effective methods can be utilized, depending on the system's size and terrain. It should also be made clear that "inspection cycle" is not intended to mean "pruning cycle". Remove 200kV threshold, FERC NOPR Paragraph 385- CenterPoint Energy believes the applicability of FAC-003-1 should be "to all transmission lines operated at 200kV and above and to any lower voltage lines

Question #1			
Commenter	**Yes**	**No**	**Comment**
			designated by the regional reliability organization as critical to reliability", because such a standard most closely matches the vegetation management reporting requirements from Docket EL04-52-000. Voltages below this threshold are not likely to impact the reliability of the Bulk Power System. Further, regional reliability organizations have the authority to designate lower voltages critical to reliability as appropriate. The proposed change is unnecessary. IEEE Standard as basis for minimum clearance to prevent flashover (Clearance 2) - CenterPoint Energy believes that the IEEE standard is sufficient and appropriate as a basis to determine the specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions (Clearance 2). Clearance 2 also must consider additional clearance for the dynamic movement of the transmission conductors to avoid vegetation related outages. Thus, the minimum clearances that a transmission owner must identify and document depend on a variety of conditions including, but not limited to, transmisison line voltage, temperature, wind velocities, and altitude.
Response: ▪ The FERC is no longer indicating a need to develop a requirement for a minimum inspection cycle (March 16, 2007 Order 693) and stakeholders indicated they did not support this change, so it was removed from the SAR. ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary. ▪ The Drafting Team agrees with the commenter and recognizes that the IEEE standard is applicable.			

Question #1			
Commenter	**Yes**	**No**	**Comment**
Central Hudson Gas & Electric		☑	The proposed revisions listed under the FERC NOPR do not provide proper justification to alter the requirements in the current FAC-003-1 document that was adopted one year ago. First, "a minimum vegetation inspection cycle that allows variation in physical difference" is already called for under the current standard. As stated in Section R1.1. of FAC-003-1, a schedule already should be defined under the transmission vegetation management program (TVMP). This schedule already allows for "variation in physical difference" since the current standard states that "this schedule should be flexible enough to adjust for changing conditions." Secondly, under Applicability Section 4.3., the current standard already allows for lines with lower voltage than 200kV to be "designated by the RRO as critical" and therefore applicable to the standard. Removal of the 200kV benchmark is not needed. And lastly, under the FERC staff report, the IEEE standard provides guidance in clearances and has been the industry standard for many years. If FERC objects to using this standard then they should provide clearances that can be discussed and agreed upon by the transmission owners.
Response: ▪ The FERC is no indicating a need to develop a requirement for a minimum inspection cycle (March 16, 2007 Order 693) and stakeholders indicated they did not support this change, so it was removed from the SAR. ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary. ▪ The Drafting Team agrees with the commenter and recognizes that the IEEE standard is applicable.			
Southern California Edison		☑	There was no empirical or anecdotal evidence presented by FERC staff to support the Commission's view that the reliability of the Bulk Power System will be enhanced with further revisions to FAC-003-1. This standard was the subject of vigorous industry debate in a previous SAR. Although it is far from perfect, the proposed revisions will not improve reliability and may very well damage existing VM programs.

Response:
▪ The Drafting Team believes a revised standard is justified because it needs to include the following NEW procedural changes:
    o Re-format FAC-003-1 to conform to the current Standards Development Procedure.
    o Remove references to RRO in the standard and substitute a responsible entity.			

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Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels.
The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.
</td></tr>
<tr><td>Baltimore Gas and Electric</td><td></td><td>☑</td><td>The revisions listed in the NOPR and FERC Staff Report do not provide the necessary justification to alter the requirements in the current FAC-003-1 document. The existing requirements already allow for each utility to specify the inspection requirements. There is no need to more prescriptive. The existing requirements already allow for the ERO to designate critical lines less than 200 kV so removal of the 200 kV benchmark is unecessary. The IEEE Standard is worthwhile to keep as a benchmark without which there would be no solid guidance for minimum clearances.</td></tr>
<tr><td colspan="4">Response:
The Drafting Team believes a revised standard is justified because it needs to include the following NEW procedural changes:
Re-format FAC-003-1 to conform to the current Standards Development Procedure.
Remove references to RRO in the standard and substitute a responsible entity.
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The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.
The FERC is no indicating a need to develop a requirement for a minimum inspection cycle (March 16, 2007 Order 693) and stakeholders indicated they did not support this change, so it was removed from the SAR.
The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary.
The Drafting Team agrees with the commenter and recognizes that the IEEE standard is applicable.
</td></tr>
<tr><td>Southern Company Transmission</td><td>☑</td><td>☑</td><td>We are not sure what you are asking? If you are asking whether we support the standard as it exists today-Southern does! If you are asking whether Southern Co. supports the changes being recommended in this Standard-we DON"T.

The present standard appears to be serving its intended purpose and the industry as currently written. The standard should not be revised until it has demonstrated it is ineffective or inadequate for ensuring the reliability of the nation's transmission grid.

Any changes to the standard should be based on empirical data rather than the assumption that the Standard is not serving its intended purpose. The standard has not been in effect long enough to determine if it is ineffective.</td></tr>
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The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.</td></tr>
<tr><td>TVA</td><td>☑</td><td>☑</td><td>As worded this question is confusing however the following comments are presented on the SAR:
The current standard contains appropriate requirements and measures to ensure that vegetation related outages will not cause cascading transmission blackouts. Mandating new explicit inspection cycle frequencies will not enhance nor ensure reliability by inspecting more or less frequently. The current minimum vegetation clearances at maximum operating conditions that are established within the owner's program, which is auditable by the ERO, is sufficient to prevent vegetation related cascading transmission
blackouts. Extending the requirements to a much a larger population of lines would reduce the current focus on the most important lines (those >200 kV). The IEEE standard when used as the minimum vegetation clearance distance at maximum operating condition will ensure desired performance of the lines. A standard of zero tolerance for vegetation related outages in the ROW is not a weak standard on compliance.</td></tr>
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<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td>Florida Power and Light Company</td><td>☑</td><td></td><td>FPL recognizes the need to address the concerns outlined in the NOPR and by the FERC Staff.</td></tr>
<tr><td colspan="4">Response:
The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes:
Re-format FAC-003-1 to conform to the current Standards Development Procedure.
Remove references to RRO in the standard and substitute a responsible entity.
Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity.
The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.</td></tr>
<tr><td>Public Service Commission of South Carolina</td><td>☑</td><td></td><td></td></tr>
<tr><td>Manitoba Hydro</td><td>☑</td><td></td><td></td></tr>
<tr><td>IESO Ontario</td><td>☑</td><td></td><td></td></tr>
<tr><td>Salt River Project</td><td>☑</td><td></td><td></td></tr>
<tr><td>ISO New England</td><td>☑</td><td></td><td></td></tr>
<tr><td>Dominion - Electric Transmission</td><td>☑</td><td></td><td></td></tr>
<tr><td>Midwest Reliability Organization</td><td>☑</td><td></td><td></td></tr>
<tr><td>ISO/RTO Council Standards Review Committee</td><td>☑</td><td></td><td></td></tr>
<tr><td>Allegheny Power</td><td>☑</td><td></td><td></td></tr>
</table>

2. Do you agree with the scope of the SAR? If not, please explain in the comment area.

Summary Consideration: Many commenters indicated there is no need to change the applicability of the requirements in this standard. The FERC indicated that the Standard Drafting Team should review and consider whether a change to the applicability to voltage <200kV is necessary.

Furthermore, some commenters expressed support for the IEEE standard's use in the FAC-003-1 Standard while the FERC declines to endorse the use of the IEEE standard as the 'only' minimum clearance. The SAR was revised to indicate that the Standard Drafting Team will seek to clarify the rationale for the use of the IEEE standard in supplemental reference material to be prepared as part of the scope of this SAR.

Question #2			
Commenter	**Yes**	**No**	**Comment**
Bonneville Power Administration	☑		Since this posting is for comment it would have been nice to provide more information as to why the FERC staff objects to the IEEE standard (since it meets the guidelines for as a North America standard. Also, why are stakeholders concerned with Reliability Coordinators vs. RRO?
Response: ▪ The Drafting Team recognizes that the IEEE standard is applicable. The FERC staff has questioned the applicability of the IEEE standard and the Drafting Team agreed to address their questions and concerns. ▪ The Drafting Team believes a revised standard is justified because it needs to include the following NEW procedural changes: o Re-format FAC-003-1 to conform to the current Standards Development Procedure. o Remove references to RRO in the standard and substitute a responsible entity. Making FAC-003 applicable to the RRO is in violation of the legislation that established the ERO. This legislation states that enforceable standards can apply only to owners, users and operators of the bulk power system. o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels.			
Bandera Electric Coop.	☑	☑	As submitted, the SAR appears to completely re-open this standard negating many months of work and industry comment to reach the consensus reflected in the current FAC-003.
Response: ▪ The ERO Rules of Procedure include the latest versions of the Reliability Standards Development Procedure Manual and the Sanctions Guidelines. These documents were approved following the approval of FAC-003-1. FAC-003-1 will need to be revised to bring the standard into conformance with these documents.			
Northeast Power Coordinating Council		☑	See response to question 1, above.
Response: See the drafting team's response to your comments on question 1.			
CenterPoint Energy Houston Electric, LLP		☑	CenterPoint Energy does not agree with the scope of the SAR for the reasons discussed in response to question 1.

Question #2			
Commenter	**Yes**	**No**	**Comment**
Response: See the drafting team's response to your comments on question 1.			
Central Hudson Gas & Electric		☑	See comments above.
Response: See the drafting team's response to your comments on question 1.			
American Electric Power		☑	American Electric Power is not aware of any evidence to support a need for revising the vegetation management standard.
Response: ▪ The ERO Rules of Procedure include the latest versions of the Reliability Standards Development Procedure Manual and the Sanctions Guidelines. These documents were approved following the approval of FAC-003-1. FAC-003-1 will need to be revised to bring the standard into conformance with these documents.			
FRCC		☑	As stated in this SAR comment form, the improvements should be made to bring the standard into conformance with the Reliability Standards Development Procedure which at this time is version 6.0, adopted by NERC BOT, 11/1/2006. The SAR scope via the attached Standard Review Guidelines includes two areas not defined within the procedure. The Mitigation Time Horizons and definitions for the violation severity levels (VSLs), Lower, Moderate, High and Severe. We understand the description of Mitigation Time Horizons and definitions for VSLs are included in the SAR (the concept of Violation Time Horizons is included in the Sanctions Guidelines, appendix 4B, NERC Compliance Filing to FERC dated October 18th, 2006), but these discrepancies are part of a broader policy issue and since their use is not clearly stipulated in the NERC Reliability Standards Development Procedure, including them in the scope of the SAR is premature and will cause unnecessary confusion to stakeholders and regulators. The process is requesting the industry to comment on a scope that is defined outside the reliability standards process and as such is subject to revisions and interpretations outside the process as well. This appears inappropriate and at the extreme will lead to inconsistent understanding, measurement and enforcement of compliance actions. The Mitigation Time Horizons and VSL levels should be defined in the Reliability Standards Development Procedure prior to inclusion in the scope of a SAR. Specific Items Within Current SAR Scope:

Question #2			
Commenter	**Yes**	**No**	**Comment**
			The establishment of minimum inspection cycles has been addressed previously, in the development of the current standard and was found very problematic given the large variety of vegetative conditions throughout North America. The vegetation that was identified as a contributing cause to the 2003 Northeast Blackout had already been identified by previous inspection activities. It was the failure to take action on the known site conditions that contributed to the event. Therefore, a minimum inspection cycle would still NOT have prevented or mitigated the scope of the Blackout. The current 200 kV threshold ensures that vegetation management efforts are focused on the critical bulk power transfer lines and that TVM efforts are not diluted by including additional lower voltage lines. In practicality, the RRO designation process provides the necessary flexibility to the Regions to address localized areas where bulk power system reliability may be compromised by lower voltage vegetation outages. To note as well, Northeast Blackout related vegetation outages which initiated the cascade occurred on lines that operate at 345 kV, well above the current threshold. The FRCC supported the development of Clearance 2, as established in the current standard, as this was a consensus selection by not only the subject matter experts, but many industry participants. Picking the ANSI Z133.1 Table 1 or 2 as the NOPR suggests, could immediately place thousands of miles of transmission lines out of compliance even though operating data indicates that the lines have performed satisfactorily for years. The concern would be, the resulting dilution of valuable industry and regulator resources. The SAR includes the following stakeholder comment: "Too weak on compliance" . We caution that we feel the compliance section does need refining, but that in a world of limited resources should focus on trends in vegetation outages and not necessarily on single outages. For transmission owners, two outages on a radial 230 kV circuit should not carry the same penalty as eight outages on multiple 230 kV circuits within a network. We would recommend that compliance be refined to identify trends, relevance and risk probability to help the industry focus their resources appropriately.

Response:

- The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes:

<table>
<tr><th colspan="4">Question #2</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td colspan="4">o Re-format FAC-003-1 to conform to the current Standards Development Procedure.
o Remove references to RRO in the standard and substitute a responsible entity.
o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels.
▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to <200kV is necessary.
▪ The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.</td></tr>
<tr><td>ITC Transmission</td><td></td><td>☑</td><td>The Standard Drafting Team should not be given lattitude to "include other improvements to the standards deemed appropriate by the drafting team." The purpose of the SAR is to identify the changes contemplated by the need for the Standard Revision. If there are changes that the SAR requestor would like to make to the Standard, they should be spelled out in the SAR. If the SAR requestor does not really know the changes that should be made to the standard, then the SAR should be withdrawn until the need for a SAR can be adequately justified.</td></tr>
<tr><td colspan="4">Response:
▪ The Drafting Team agrees and has removed the paragraph in the brief description of the SAR that opened the scope to other improvements.</td></tr>
<tr><td>ISO/RTO Council Standards Review Committee

ISO New England</td><td></td><td>☑</td><td>The SRC (ISO-NE) would suggest that the SAR be clear that it will be a complete review of the subject requirements: to include the addition, deletion and modification of
requirements as agreed to by public consensus.</td></tr>
<tr><td colspan="4">Response:
▪ The Drafting Team removed the paragraph in the brief description of the SAR that opened the scope to other improvements. The Drafting Team concurs with consensus of the commenters that the technical elements of this standard are complete. The intent of the SAR modification is to address FERC issues and to conform to updates in the Reliability Standards Development Procedure and Sanctions Guidelines.</td></tr>
<tr><td>Hydro-Québec TransÉnergie</td><td>☑</td><td>☑</td><td>FERC staff report has objection to use IEEE standard. Should we understand that another standard is recommended instead?</td></tr>
<tr><td colspan="4">Response:
▪ The Drafting Team recognizes that the IEEE standard is applicable. The FERC staff has questioned the applicability of the IEEE standard and the Drafting Team agreed to address their questions and concerns.</td></tr>
<tr><td>Hydro One Networks, Inc.</td><td></td><td>☑</td><td>To address FERC's objection to use the IEEE standard, it is necessary to clarify the objective of the Vegetation Management Standard. As we understand it, the focus of the FAC-003-1 standard is system reliability and as such, the responsibility and authority on defining and applying the safety margins is rightly assigned to the transmission owner. We request clarification on how employing safety factors will address reliability and how prescribing minimum clearances within the standard will</td></tr>
</table>

Question #2			
Commenter	**Yes**	**No**	**Comment**
			improve reliability. Please note that the Canadian Standards Association is revising standard C22.3 No. 1 - Overhead Systems. The new version will include clearances to vegetation and the proposed minimum clearances are in alignment with FAC-003-1.
Response: ▪ The Drafting Team recognizes that the IEEE standard is applicable. The FERC staff has questioned the applicability of the IEEE standard and the Drafting Team agreed to address their questions and concerns.			
SERC Reliability Corporation Progress Energy	☑	☑	Minimum Inspection Intervals: The SERC VMS (Progress Energy) believes that FAC 003-1 provides the proper amount of flexibility regarding vegetation inspection cycles and that the Standards Drafting Team should not impose minimum inspection intervals on a continent with such regional diversity in climate and plant life. The purpose of Requirement 1.1 of standard FAC-003-1 is to put the responsibility for proper inspection cycles on the entity that knows the local conditions and can best define what that inspection frequency should be, the Transmission Owner. Both NERC and the FERC staff have recognized that various local conditions can have an affect on the determination of adequate inspection frequencies. Establishing a mandatory minimum inspection frequency could have two detrimental effects on the industry. First, where a particular region is heavily forested and has heavy rainfall along with extended or year round growing seasons, a "back stop" minimum inspection frequency could lead transmission owners to conduct inspections less frequently than required by the local conditions. This could result in a Transmission Owner complying with the standard while not adequately protecting the reliability of that region's transmission system. This is a "lowest common denominator" approach which FERC has repeatedly stated is inappropriate for the reliability standards. Second, where a particular region is arid, sparsely forested or has a minimum growing season, a "back stop" minimum could require a more frequent interval than is realistically needed. This would result in increased and unnecessary costs for electric utility customers without providing an increase in system reliability. In its discussion of inspection intervals, FERC indicates that a "one-year vegetation

Question #2			
Commenter	**Yes**	**No**	**Comment**
			inspection cycle is reasonable." FERC NOPR, 10/20/2002 paragraph 383. The Commission continues by stating "a one-year inspection cycle is the 'norm' for the industry, but not the lowest common denominator…" It follows from this observation that the industry as a whole recognizes and follows appropriate inspection intervals without a need to change the standard. Further, FERC also states "some variation to a continent-wide, one-year minimum inspection cycle should be allowed due to physical differences such as climate and species of vegetation." FERC NOPR 10/20/2006, paragraph 382. FERC's express recognition that a "one size fits all" approach is not appropriate further supports the SERC VMS's contention that the existing inspection requirements in standard FAC-003-1 should remain unchanged. Finally, the performance metrics of FAC-003 require the reporting of applicable transmission interruptions that are caused by vegetation. This process should appropriately identify Transmission Owners' inspection cycles that are not adequate. In this event, the ERO has the authority to engage the Transmission Owner in enforcement compliance actions and, therefore, can remedy any vegetation-related outage that is attributed to the Transmission Owner's inspection frequency. Standard Applicability: The SERC VMS disagrees with the proposal to revise the 200 kV threshold for determining facilities subject to this standard. The majority of transmission facilities below 200 kV have significantly different design/construction/operating characteristics and have not been cited as impacting bulk power system reliability. For example, the Final Report on the August 14, 2003 Blackout in the United states and Canada: Causes and Recommendations April 2004 by the U.S.- Canada Power System Outage Task Force and all referenced major blackouts(pages 103-115) in that report, cited only outages which involved vegetation at line voltages above 200 kV. Generally applying requirements appropriate for 200 kV lines to lines less than 200 kV will result in significant documentation and reporting of items such as restrictions, mitigation plans, off right-of-way vegetation-related outage investigation/information and other issues, all of which dilutes the focus on lines that directly impact bulk power system reliability.

Question #2			
Commenter	**Yes**	**No**	**Comment**
			Revising the standard to use general criteria or broad language for defining "Bulk Power System" transmission lines covered by the standard could become a "one size fits all" approach. If that approach were taken, the standard would cover a significant number of transmission lines that have no direct impact on bulk power system reliability under standard planning/operating conditions, resulting in a significant increase in costs for electric customers without improving "Bulk Power System" system reliability. The SERC VMS believes that the applicability provision of the standard should instead focus attention of the standard only on the transmission lines below 200 kV that directly impact "Bulk Power System" reliability, as the current version requires. In sum, while the SERC VMS (Progress Energy) recognizes some validity in the Commission's concern, the SERC VMS (Progress Energy) recommends that the applicability provision of this standard should be revised only if existing system design, planning or operating reliability criteria and parameters are considered as a basis for defining the applicability of the standard. To that end, the SERC VMS recommends each Regional Entity (RE) determine applicability of FAC-003 to those lines within the region that are between 100 kV and 200 KV if and only if they are identified as operationally significant elements of Interconnection Reliability Operating Limits ("IROLs"). IEEE Standard for Minimum Clearances: The SERC VMS disagrees with objections in the FERC staff report to the use of the IEEE 516-2003 clearance as the minimum acceptable distances for "Clearance 2". The IEEE 516-2003 tables are appropriate for defining the minimum acceptable clearances to prevent flashover between conductors and vegetation under all rated electrical operating conditions. Closer minimum clearances such as the minimum length of a support insulator could have been adopted as a "lowest common denominator" clearance. However the clearance in IEEE 516-2003 was adopted to ensure an additional margin of reliability. FERC staff references ANSI Z-133 which is a safety standard that addresses worker safety as well as the safety of the general public. As such, the purpose of ANSI Z-133 is to address worker safety and is not focused on transmission line reliability, which is the purpose of FAC-003-1. OSHA, NESC and other related safety standards have clearances in excess of IEEE 516-2003. Those clearances are clearly focused on safety issues and will still apply

Question #2			
Commenter	**Yes**	**No**	**Comment**
			to other aspects of design and operation of electric facilities (such as public and worker safety) but do not need to be referenced in a vegetation management reliability standard.
Response: ▪ The FERC is no longer indicating a need to develop a requirement for a minimum inspection cycle (March 16, 2007 Order 693) and stakeholders indicated they did not support this change, so it was removed from the SAR. ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary. ▪ The Drafting Team recognizes that the IEEE standard is applicable. The FERC staff has questioned the applicability of the IEEE standard and the Drafting Team agreed to address their questions and concerns.			
TVA		☑	Minimum Inspection Intervals: FAC 003-1 provides the proper amount of flexibility regarding vegetation inspection cycles and that the Standards Drafting Team should not impose minimum inspection intervals on a continent with such regional diversity in climate and plant life. Requirement 1.1 of standard FAC-003-1 places the responsibility for proper inspection cycles on the entity that knows the local conditions and can best define what that inspection frequency should be, the Transmission Owner. Both NERC and the FERC staff have recognized that various local conditions can have an affect on the determination of adequate inspection frequencies. Establishing a mandatory minimum inspection frequency could have two detrimental effects on the industry. First, where a particular region is heavily forested and has heavy rainfall along with extended or year round growing seasons, a "back stop" minimum inspection frequency could lead transmission owners to conduct inspections less frequently than required by the local conditions. This could result in a Transmission Owner complying with the standard while not adequately protecting the reliability of that region's transmission system. This is a "lowest common denominator" approach which FERC has repeatedly stated is inappropriate for the reliability standards. Page 5 of 6 January 15, 2007 Second, where a particular region is arid, sparsely forested or has a minimum growing season, a "back stop" minimum could require a more frequent interval than is realistically needed. This would result in increased and unnecessary costs for electric utility customers without providing an increase in system reliability. In its

Question #2			
Commenter	**Yes**	**No**	**Comment**
			discussion of inspection intervals, FERC indicates that a “one-year vegetation inspection cycle is reasonable.” FERC NOPR, 10/20/2002 paragraph 383. The Commission continues by stating “a one-year inspection cycle is the ‘norm’ for the industry, but not the lowest common denominator…” It follows from this observation that the industry as a whole recognizes and follows appropriate inspection intervals without a need to change the standard. Further, FERC also states “some variation to a continent-wide, one-year minimum inspection cycle should be allowed due to physical differences such as climate and species of vegetation.” FERC NOPR 10/20/2006, paragraph 382. FERC’s recognition that a “one size fits all” approach is not appropriate supports maintaining the existing inspection requirements in standard FAC-003-1. Finally, the performance metrics of FAC-003 require the reporting of applicable transmission interruptions that are caused by vegetation. This process will identify Transmission Owners’ inspection cycles that are not adequate. In this event, the ERO has the authority to engage the Transmission Owner in enforcement compliance actions and, therefore, can remedy any vegetation-related outage that is attributed to the Transmission Owner’s inspection frequency. Standard Applicability: The 200 kV threshold for determining facilities subject to this standard should not be revised. The transmission facilities below 200 kV have not been cited as impacting bulk power system reliability. The Final Report on the August 14, 2003 Blackout in the United states and Canada: Causes and Recommendations April 2004 by the U.S.- Canada Power System Outage Task Force and all referenced major blackouts(pages 103-115) in that report, cited only outages which involved vegetation at line voltages above 200 kV. Generally applying requirements appropriate for 200 kV lines to lines less than 200 kV will result in significant documentation and reporting of items such as restrictions, mitigation plans, off right-of-way vegetation-related outage investigation/information and other issues, all of which dilutes the focus on lines that directly impact bulk power system reliability. Revising the standard to use general criteria or broad language for defining "Bulk Power System" transmission lines covered by the standard could become a “one size fits all” approach. If that approach were taken, the standard would cover a significant

Question #2			
Commenter	**Yes**	**No**	**Comment**
			number of transmission lines that have no direct impact on bulk power system reliability under standard planning/operating conditions, resulting in a significant increase in costs for electric customers without improving "Bulk Power System" system reliability. The SERC VMS believes that the applicability provision of the standard should instead focus attention of the standard only on the transmission lines below 200 kV that directly impact "Bulk Power System" reliability, as the current version requires. The applicability provision of this standard should be revised only if existing system design, planning or operating reliability criteria and parameters are considered as a basis for defining the applicability of the standard. To that end, each Regional Entity (RE) should determine the applicability of FAC-003 to those lines within the region that are between 100 kV and 200 KV if and only if they are identified as operationally significant elements of Interconnection Reliability Operating Limits ("IROLs"). IEEE Standard for Minimum Clearances: Page 6 of 6 January 15, 2007 The IEEE 516-2003 should continue to be used as the minimum acceptable distances for "Clearance 2". The IEEE 516-2003 tables are appropriate for defining the minimum acceptable clearances to prevent flashover between conductors and vegetation under all rated electrical operating conditions. Closer minimum clearances such as the minimum length of a support insulator could have been adopted as a "lowest common denominator" clearance. However the clearance in IEEE 516-2003 was adopted to ensure an additional margin of reliability. FERC staff references ANSI Z-133 which is a safety standard that addresses worker safety as well as the safety of the general public. As such, the purpose of ANSI Z-133 is to address worker safety and is not focused on transmission line reliability, which is the purpose of FAC-003-1. OSHA, NESC and other related safety standards have clearances in excess of IEEE 516-2003. Those clearances are clearly focused on safety issues and will still apply to other aspects of design and operation of electric facilities (such as public and worker safety) but do not need to be referenced in a vegetation management reliability standard.
Response:			

<table>
<tr><th colspan="4">Question #2</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td colspan="4">The FERC is no longer indicating a need to develop a requirement for a minimum inspection cycle (March 16, 2007 Order 693) and stakeholders indicated they did not support this change, so it was removed from the SAR.
The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary.
The Drafting Team recognizes that the IEEE standard is applicable. The FERC staff has questioned the applicability of the IEEE standard and the Drafting Team agreed to address their questions and concerns.</td></tr>
<tr><td>Midwest Reliability Organization</td><td>☑</td><td>☑</td><td>The scope of this SAR would have been better defined if the complete Standard Review Form for the Vegetation Management Standard had been included as an attachment to the SAR. Several issues in the Standard Review Form for this SAR were excluded with this posted SAR. For example, issues related to R3.1 and R3.2.

The MRO is also not clear on the scope of the instruction to the SDrafting Team to "Expand the applicability to include transmission lines operated at 200 kV and above and other facilities as determined by the ERO so that the Reliability Standard applies to Bulk-Power System transmission lines that have an impact on reliability" It is not clear to the MRO what is meant by "as determined by the ERO". What process will the ERO use? The ERO should use stakeholder input to make this determination. The current standard is applicable to all transmission lines 200 kV and above and to any lower voltage lines designated by the RRO as critical to the electric system in the region. Will the ERO be in a position to assume the assessment of the criticality of lines less than 200 kV without input from the entities that have historically operated in each region?

Also, the MRO is not clear on what is included in the term Bulk-Power System. What guidance will the SDrafting Team have in determining what is meant by the Bulk-Power System? Since this relates to the large issue of the Bulk Electric System versus Bulk-Power System is this SAR the appropriate vehicle to address this issue? There should be a wider discussion and resolution to this issue for consistent application to all standards by all SDrafting Teams.</td></tr>
<tr><td colspan="4">Response:
The comments on R3.1 and R3.2 were developed by NERC staff in a previous version of this SAR and these have been deleted from the revised SAR. Instead, the Standard Drafting Team will apply the Standard Review Guidelines to the Standard.
The comments from the FERC NOPR were removed from the revised SAR.
The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary.</td></tr>
<tr><td>Florida Power and Light Company</td><td></td><td>☑</td><td>Establishing minimum inspection cycles is a very problematic given the large variety of vegetative conditions throughout North America. In reality most lines are inspected annually for all failure modes including vegetation. The trees that played a part of the North East Blackout were known and on the radar screen. The utility</td></tr>
</table>

Question #2			
Commenter	**Yes**	**No**	**Comment**
			failed to take action. The inspection did not prevent the outage from occurring. The failure to take action on the known site condition was the contributing factor to the Blackout. We do not understand the need to establish separate criteria other than the RRO's critical designation. A transmission line is either necessary to the system to prevent an overload situation or it is not. To add lines that might not be critical to the system would dilute the effort needed to insure that the critical lines are properly maintained. Since system stability is the focus of the standard, what criteria would be used to bring additional lower voltage lines under the standard. When developing Clearance 2, the committee needed to determine a distance at which a Transmission Owner could be out of compliance even though no interruption has occurred. In a sense this is the maximum 'speed limit' at which the utility would be in violation. Their criteria was "How close can a tree be and not cause an outage?" The engineers on the team reviewed scientific data and current standards. The IEEE MAID standard was the consensus selection of the sub committee. All parties need to understand that this is one of the building blocks that would be used in determining the width of an easement or ROW. Picking the ANSI Z133.1 Table 1 or 2 as the NOPR suggests could immediately place thousands of miles of transmission lines out of compliance that have performed satisfactorily for years. The ANSI tables are phase to phase safety calculations when grow-in tree interruptions are phase to ground situations.
Response: ▪ The FERCis no longer indicating a need to develop a requirement for a minimum inspection cycle (March 16, 2007 Order 693) and stakeholders indicated they did not support this change, so it was removed from the SAR. ▪ The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes: o Re-format FAC-003-1 to conform to the current Standards Development Procedure. o Remove references to RRO in the standard and substitute a responsible entity. o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels.			
Public Service Commission of South Carolina		☑	We are concerned that lowering the applicability threshold to all lines below 200KV will divert attention and resources from the higher voltage lines which have a higher probability of causing grid problems. The RRO and transmission owners best know which lower voltage lines should be included under the requirements of the

Question #2			
Commenter	**Yes**	**No**	**Comment**
			standard.
Response: ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary.			
IESO Ontario		☑	With respect to the item in the Brief Description section under FERC NOPR: "Remove the applicability to transmission lines operated at 200 kV and above so that the Reliability Standard applies to Bulk Power System transmission lines that have an impact on reliability as determined by the ERO." It is the IESO's view that requiring the ERO to make these determinations, is inappropriate. We believe the standard should remain applicable to lines 200 kV and above and lines below 200 kV as determined by the Reliability Coordinator, similar to the PRC-023 standard. The IESO also suggests that it be made clear in the SAR that it will be a complete review of the subject requirements: to include the addition, deletion and modification of requirements, as agreed to by public consensus.
Response: ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to transmission voltage class <200kV is necessary. ▪ The Drafting Team removed the paragraph in the brief description of the SAR that opened the scope to other improvements. The Drafting Team concurs with consensus of the commenters that the technical elements of this standard are complete. The intent of the SAR modification is to address FERC issues and to conform to updates in the Reliability Standards Development Procedure and Sanctions Guidelines.			
Dominion - Electric Transmission		☑	We disagree with the proposal from FERC NOPR regarding removing applicability to transmission lines >200kv. The proposal to apply the Standard to lines the ERO deems to have an impact on reliability can create inconsistency between regions and is a "fill in the blank" requirement. It is not clear whether the proposed change would increase or decrease the number of transmission lines which are subject to reportable outages. In addition, we support the Standard's existing language that limits reporting to locked out lines only.
Response: ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary.			
Southern California Edison		☑	The Commission's reccomendation to develop a "minimum" vegetation inspection cycle is untimely and their proposal to revise the scope ignores plain language contained in the standard. In SCE's view, the Commission's incessant need to bolt on a "widget count" requirement (for minimum inspection cylcles) will likely lead to an increased number of tree-to-line contacts. Unlike the static equipment located in power plants

Question #2			
Commenter	**Yes**	**No**	**Comment**
			and substations, trees and foliage in and around Transmission ROWs are subject to uncontrolable and fairly unpredictable natural forces. Industry debate during the previous SAR and comments submitted in the recently concluded NOPR demonstrate this approach is unsound. Transmission Owners in neighboring states commented that their cycles and trimming protocols vary from year to year and sometimes circuit to circuit. Instituting a minimum inspection cycle of 3 years (for example) might appeal to certain TOs because doing so will support a case for increased rate recovery. But for others, a mandatory 3 year inspection cycle will offer a potential cost reduction opportunity because they are already following a voluntary 2 year inspection cycle. The Commission's other reccomendedation should be rejected because subsection 4.3 clearly covers transmission lines operating below 200 kV. ["….any lower voltage lines designated by the RRO as critical to the reliabilty of the electric system in the region."] FAC-003-1 requires Transmission Owners to - "define a schedule for and the type (aerial, ground) of ROW vegetation inspections". Although the Commission staff would prefer a specific time duration because it suits their "check list" style of enforcement, the prudent thing to do is allow TOs the latitude to manage their part of the bulk system and hold each accountable to the existing compliance measures in FAC-003-1. Similarly, revising subsection 4.3 in deferrence to the Commission's or staff's misinterpretation of plain text is unwarranted.
Response: ▪ The FERC is no longer indicating a need to develop a requirement for a minimum inspection cycle in its March 16, 2007 Order 693 and stakeholders indicated they did not support this change, so it was removed from the SAR. ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary.			
New York State Electric and Gas Corporation		☑	The current standard FAC 003 1 should be monitored for one to two full years after all segments have been implemented. February 14, 2007 is too soon to determine if a revision is required. The standard should apply to 200 KV lines and higher voltages to prevent cascading type power outages. The IEEE table 516 is referenced as a minimum guide for table 2 clearances. This table provides clear and measurable distances that can used for audits and

Question #2			
Commenter	**Yes**	**No**	**Comment**
			potential compliance issues. The current standard allows enough flexibility so that the clearance 2 distance can be expanded if a utility feels that is the correct approach in a specfic region. The physical differences between electric systems, tree growth rates, local regulations, climate, and geography make it important to provide a flexible standard, a "one size fits all" approach will not be effective in the long run.
Response: ▪ The ERO Rules of Procedure include the latest versions of the Reliability Standards Development Procedure Manual and the Sanctions Guidelines. These documents were approved following the approval of FAC-003-1. FAC-003-1 will need to be revised to bring the standard into conformance with these documents. ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary. ▪ The Drafting Team recognizes that the IEEE standard is applicable. The FERC staff has questioned the applicability of the IEEE standard and the Drafting Team agreed to address their questions and concerns. ▪ The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes: o Re-format FAC-003-1 to conform to current Standards Development Procedure. o Remove references to RRO in the standard and substitute a responsible entity. o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels. ▪ The FERC is no longer indicating a need to develop a requirement for a minimum inspection cycle (March 16, 2007 Order 693) and stakeholders indicated they did not support this change, so it was removed from the SAR.			
Manitoba Hydro		☑	The scope of the SAR is too vague on several important points. (1) There is no definition for the phrase bulk-power system - it would be therefore unclear as to what facilities would be covered by the standard. What guidance will the SDrafting Team have in determining what is meant by the bulk-power system? Since this relates to the large issue of the Bulk Electric System versus Bulk-Power System is this SAR the appropriate vehicle to address this issue? There should be a wider discussion and resolution to this issue for consistent application to all standards by all SDrafting Teams. (2)The concept of Mitigation Time Horizons has not been defined and the use of Mitigation Time Horizons has not been detailed. (3)The ERO is not the appropriate entity to determine which lines have an impact on reliability. This should be Transmission Operators in coordination with Reliability Coordinators. If this standard is to include the methodology to determine which lines have a reliability impact on the bulk-power system, the the applicability of the

<table>
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<tr><td></td><td></td><td></td><td>standard will have to include other entities besides the Transmission Owners.

(4) The SAR refers to RA, i.e., Reliability Authority. This entity no longer exists in the Functional Model but has been replaced by Reliability Coordinator.

(5) What is meant by "Too weak on compliance"?

(5) FERC objects to IEEE Standard but there is no other guidance to the standard drafting team.</td></tr>
<tr><td colspan="4">Response:
▪ The comments regarding Bulk Power System in the FERC NOPR comments were removed from the revised SAR.
▪ The ERO Rules of Procedure require the inclusion of time horizons for each standard – these are defined in the Sanctions Guidelines and are used to help determine the size of a sanction.
▪ The revised SAR does not include the language proposing that the ERO determine which lines have an impact on reliability.
▪ The reference to Reliability Authority (RA) was removed from the revised SAR.
▪ The reference, ‘Too weak on compliance’ was removed from the revised SAR as it was addressed with the development of Version 1 of this standard.
▪ The Drafting Team recognizes that the IEEE standard is applicable. The FERC staff has questioned the applicability of the IEEE standard and the Drafting Team agreed to address their questions and concerns.</td></tr>
<tr><td>Southern Company Transmission</td><td></td><td>☑</td><td>The scope of the SAR should be limited to formatting and changes of wording that recognize the formation of the ERO and its procedures.

The drafting team should not attempt to re-write the present clearance requirements, which are based on IEEE flashover distances. The clearance requirements in the orignal standard were written through extensive evaluation and input from the industry. There was strong industry consensus on the present language and the standard is serving its intended purpose very well. The clearance standard should not be revised until it is found to be ineffective or inadequate.

The drafting team should not attempt to change the applicability of the present standard. The present standard applies to all 200 KV and higher lines, plus any other line the Regional Entity deems critical. A change in wording to make the standard apply to any bulk power system transmission line deemed critical by the ERO does not provide any additional safeguard that is not already contained in the standard as presently written.</td></tr>
<tr><td colspan="4">Response:
▪ The Drafting Team recognizes that the IEEE standard is applicable. The FERC staff has questioned the applicability of the IEEE</td></tr>
</table>

Question #2			
Commenter	**Yes**	**No**	**Comment**
standard and the Drafting Team agreed to address their questions and concerns. ▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary.			
Baltimore Gas and Electric		☑	As noted above.
Response: See response to your question #1 comment above.			
Salt River Project	☑		
Allegheny Power	☑		

3. Are there additional revisions, beyond those identified in the SAR that should be addressed within the scope of this project?

Summary Consideration: Commenters suggested a number of additional revisions to the SAR related to:
- Applicability
- Right of Way (ROW) definition
- Compliance
- Clearance requirements
- Others

The SAR Drafting Team revised the SAR to consider these suggested revisions.

Question #3			
Commenter	**Yes**	**No**	**Comment**
Bonneville Power Administration	☑		It is not clear if categroy 1 and 2 refer only to occupied ROW, or also to unoccupied area reserved by the Transmission Owner for future expansion.
Response: o Category 1 outages refer to "grow-ins" inside or outside the right-of-way regardless; while a Category 2 outage applies to "fall-ins" on land that is inside the legal bounds of the right-or-way whether occupied or not. ▪ The FERC has directed the ERO to address the definition of ROW in its Order 693. ▪ As part of the SAR, the SAR Drafting Team commits the Standard Drafting Team to prepare technical reference material such as a "white paper" to aid in understanding the technical basis for the standard and, unless the requirements in the standard are modified to add more clarity, the SAR Drafting Team will recommend that the white paper include a discussion of the differences between category 1 and category 2 to address your concern.			
FRCC	☑		Requirement 3.2, item (1), the reporting exemption for outages occuring due to natural disaters should be expanded to include all vegetation outages that occur as a result of the disaster. Currently the exemption applies to vegetation from outside the ROW. As a result of significant experience with hurricanes, our operators have found that this distinction results in a waste of post-disaster resources. The standard currently requires the owner to investigate and determine the original location of the vegetation that may have caused an outage. Restoration of circuits may be delayed and often times, determination of the original location of the vegetation is not possible.
Response: ▪ The SAR Drafting Team will review the reporting exemptions to all category outages under major disasters in Requirement R3.2.			
Northeast Power Coordinating Council	☑		Only if the Bulk Power System is determined as an impact based performance based methodology.
Response:			

Question #3			
Commenter	**Yes**	**No**	**Comment**
▪ The FERC looks to the Standard Drafting Team to determine whether a change to the applicability to voltage <200kV is necessary. The comments regarding Bulk Power System in the FERC NOPR comments were removed from the revised SAR ▪			
SERC Reliability Corporation	☑		Standard Applicability: The outage reporting requirement for the RRO should be deleted. Making FAC-003 applicable to the RRO is in violation of the legislation that established the ERO. This legislation states that enforceable standards can apply only to owners, users and operators of the bulk power system. Futher, in the NOPR on NERC standards, FERC declined to approve those standards that applied to the RROs, in part because the RROs are not owners, users or operators. Compliance: The SERC VMS recommends deleting reporting requirements for Category 3 outages. These outages are not controllable, not relevant to compliance, not related to grid reliability, not related to cascading blackouts, and such reporting leads to unnecessarily biasing reliability related information.
Response: ▪ The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes: o Re-format FAC-003-1 to conform to the current Standards Development Procedure. o Remove references to RRO in the standard and substitute a responsible entity. o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels. ▪ The Standard Drafting Team intends to review reporting criteria for Category 3 outages in the proposed technical reference material and may review the reporting requirement of Category 3 outages in R.3 and R.4.			
Progress Energy	☑		Standard Applicability: The outage reporting requirement for the RRO should be deleted. Making FAC-003 applicable to the RRO is in violation of the legislation that established the ERO. This legislation states that enforceable standards can apply only to owners, users and opeartors of the bulk power system. Futher, in the NOPR on NERC standards, FERC declined to approve those standards that applied to the RROs, in part because the RROs are not owners, users or operators. Compliance: Progress Energy believes that FAC-003 should focus compliance on the issues that improve system/grid reliability. The VM standard outage reporting requirements do not focus on ensuring grid/network reliability.

Question #3			
Commenter	**Yes**	**No**	**Comment**
			Category 2 outages ("Fall-ins" from vegetation within the R/W) result in a level of non-compliance (Level 2 or 3). However, "Fall-ins", either off-R/W or within the R/W, are random events. They would not occur sequentially (i.e., a fall-in causing another line section to overload resulting in another "fall-in") and would not have the potential to cascade into a widespread blackout. This is a customer reliability issue for that line, not a grid reliability issue. While it may be worthwhile to report for tracking and trending, it is not an outage that should result in non-compliance. Category 1 "Grow-ins" include outages that result from conductor side-wing would be reported as Category 1 outages, resulting in non-compliance (Level 3 or 4). However, conductor side-swing outages are random occurrences. They are not the sequential outages that would have the potential to cascade into a widespread blackout. This is a customer reliability issue for that line, not a grid reliability issue. These types of outages should be not be considered any different than numerous other random events that result in transmission line outages.
Response: ▪ The SAR Drafting Team understands the distinction between grow-in and fall-in related outages and the prediction challenges with fall-in related outages. Modifying the compliance section is included in the scope of the SAR.			
Florida Power and Light Company	☑		Requirement 3.2 exempts reporting of outages from outside the ROW when natural disasters such as tornados or hurricanes occur. Our experience with numerous hurricanes indicates that all outages during these types of events should be exempt. The focus in these situations is to get the lines back in service and restore customers. There is insufficient manpower to adequately complete the forensics necessary to determine an accurate root cause. It is not uncommon to find vegetation debris in the lines or downed trees on the ROW in this situation. In most cases it is not possible to determine the original location of these trees. In the compliance section of the document a transmission owner becomes non compliant with a single category 1 or 2 outage. This occurs regardless of the circumstances. A non compliant penalty for a single outage in a situation where no customers were affected and the system could not have been compromised is not reasonable. It is also not an indicator of a poorly maintained system. We agree that several Category 1 or 2 interruptions could be an indicator of neglect but one is not. We recommend that The compliance section be reviewed with this in mind.
Response: ▪ The Standard Drafting Team will review the reporting exemptions to all category outages under major disasters in Requirement			

Question #3			
Commenter	**Yes**	**No**	**Comment**
R3.2. ▪ Modifying the compliance section is included in the scope of the SAR.			
Midwest Reliability Organization	☑		Since the IEEE standard does not appear to be a favorable clearance requirement, minimum clearance requirements should be tied to legal documents such as easments, state statute, or permits. This will help Transmission Owners to maintain their ROWs based on their agreements with the land owners and not rely on historical ROW management practices. It would also provide flexibility in clearance requirements based on geopraphical and climatological factors that influence different regions because landowner agreements will be different depending on local influences.
Response: ▪ The Drafting Team recognizes that the IEEE standard is applicable. The FERC staff has questioned the applicability of the IEEE standard and the Drafting Team agreed to address their questions and concerns.			
TVA	☑		Standard Applicability: The outage reporting requirement for the RRO should be deleted. Making FAC-003 applicable to the RRO is in violation of the legislation that established the ERO. This legislation states that enforceable standards can apply only to owners, users and operators of the bulk power system. Further, in the NOPR on NERC standards, FERC declined to approve those standards that applied to the RROs, in part because the RROs are not owners, users or operators. Compliance: Reporting requirements for Category 3 outages should be eliminated. These outages are not controllable, not relevant to compliance, not related to grid reliability, not related to cascading blackouts, and such reporting leads to unnecessarily biasing reliability related information.
Response: ▪ The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes: o Re-format FAC-003-1 to conform to the current Standards Development Procedure. o Remove references to RRO in the standard and substitute a responsible entity. o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels. ▪ The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System. ▪ The Standard Drafting Team intends to review reporting criteria for Category 3 outages in the proposed technical reference material and may review the reporting requirement of Category 3 outages in R.3 and R.4.			

<table>
<tr><th colspan="4">Question #3</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td>Bandera Electric Coop.</td><td></td><td>☑</td><td>See Comment #2</td></tr>
<tr><td colspan="4">Response: See response to Comment #2.</td></tr>
<tr><td>ITC Transmission</td><td></td><td>☑</td><td>We think the Standard is fine the way it is.</td></tr>
<tr><td colspan="4">Response:
▪ The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes:
o Re-format FAC-003-1 to conform to the current Standards Development Procedure.
o Remove references to RRO in the standard and substitute a responsible entity.
o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels.
▪ The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.</td></tr>
<tr><td>American Electric Power</td><td></td><td>☑</td><td>As stated in responses to questions 1 and 2, AEP believes that the current standard is adequate and that we are not aware of evidence to support a need for revising the current vegetation management standard.</td></tr>
<tr><td colspan="4">Response:
▪ The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes:
o Re-format FAC-003-1 to conform to the current Standards Development Procedure.
o Remove references to RRO in the standard and substitute a responsible entity.
o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels.
▪ The Standard Drafting Team will address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.</td></tr>
<tr><td>Southern California Edison</td><td></td><td>☑</td><td>Although SCE is wholly dissatisfied with the integration of IEEE 516-2003 into FAC-003-1 and looks forward to the day when qualified industry professionals and utility arborists are provided an opportunity to develop a reasonable and scientifically sound method for determining “minimum” tree-to-line clearances, we believe this standard should be allowed to “soak” a bit before subjecting it to further revision.</td></tr>
<tr><td colspan="4">Response:
▪ The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes:
o Re-format FAC-003-1 to conform to the current Standards Development Procedure.
o Remove references to RRO in the standard and substitute a responsible entity.
o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels.
▪ The Standard Drafting Team will address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.
▪ The Drafting Team recognizes that the IEEE standard is applicable. The FERC staff has questioned the applicability of the IEEE standard and the Drafting Team agreed to address their questions and concerns.</td></tr>
</table>

Question #3			
Commenter	**Yes**	**No**	**Comment**
New York State Electric and Gas Corporation		☑	The Vegetation Management Standard FAC 003 1 is comprehensive, and utilities following the established guidelines will be able to meet FERC's expecation of preventing bulk power delivery outages by using crisp measurable guidleines that offer limited flexiblity for varying conditions.
Response: ▪ The Drafting Team believes a revised standard is justified because it needs to include the following procedural changes: o Re-format FAC-003-1 to conform to the current Standards Development Procedure. o Remove references to RRO in the standard and substitute a responsible entity. o Add the compliance elements needed to support the Sanctions Guidelines, including time horizons, and violation severity levels, etc. ▪ The Standard Drafting Team will also address improvements identified by the FERC in its Order 693 - Mandatory Reliability Standards for the Bulk Power System.			
ISO/RTO Council Standards Review Committee		☑	
Hydro One Networks, Inc.		☑	
Allegheny Power		☑	
Dominion - Electric Transmission		☑	
CenterPoint Energy Houston Electric, LLP		☑	
ISO New England		☑	
Central Hudson Gas & Electric		☑	
Public Service Commission of South Carolina		☑	
Hydro-Québec TransÉnergie		☑	
Southern Company Transmission		☑	
IESO Ontario		☑	
Salt River Project		☑	
Baltimore Gas and Electric		☑	

Nomination Form —Transmission Vegetation Management SAR Drafting Team — Modify Standard FAC-003-1

Please return this form to sarcomm@nerc.com by **January 29, 2007**. For questions, please contact Richard Schneider at 609-452-8060 or Richard.schneider@nerc.net.

The drafting team will likely meet the end of February to respond to comments on the SAR. The complete meeting schedule has not been determined yet. It is expected the teams will meet several times in 2007 including face-to-face meetings, as well as meetings facilitated through various remote meeting technologies. **All candidates should be prepared to participate actively at these meetings.**

Name:	
Organization:	
Address:	
Office Telephone:	
E-mail:	

Please briefly describe your experience and qualifications to serve on the Transmission Vegetation Management SAR Drafting Team. Candidates should have expertise in one or more of the following areas: transmission line rights-of-way (ROW) vegetation management or ROW maintenance; transmission line design and ratings; regulatory or legal considerations in ROW maintenance; or existing codes and good practices in vegetation management. Previous experience developing or applying NERC or IEEE standards is beneficial, but not a requirement.

I represent the following NERC Reliability Region(s) (check all that apply):		**I represent the following Industry Segment (check one):**
☐ ERCOT	☐	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs and ISOs
☐ MRO	☐	3 — Load-serving Entities
☐ NPCC	☐	4 — Transmission-dependent Utilities
☐ RFC	☐	5 — Electric Generators
☐ SERC	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ SPP	☐	7 — Large Electricity End Users
☐ WECC	☐	8 — Small Electricity End Users
☐ NA – Not Applicable	☐	9 — Federal, State, and Provincial Regulatory or other Government Entities

	☐	10 – Regional Reliability Organizations and Regional Entities

Which of the following Function(s) do you have expertise or responsibilities:	
☐ Reliability Coordinator	☐ Transmission Service Provider
☐ Balancing Authority	☐ Transmission Owner
☐ Interchange Authority	☐ Load Serving Entity
☐ Planning Authority or Coordinator	☐ Distribution Provider
☐ Transmission Operator	☐ Purchasing-selling Entity
☐ Generator Operator	☐ Generator Owner
☐ Transmission Planner	☐ Resource Planner
☐ Compliance Monitor	☐ Market Operator
Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group.	
Name:	Office Telephone:
Organization:	E-mail:
Name:	Office Telephone:
Organization:	E-mail:

Standard Authorization Request Form

Revisions to FAC-003-1 Transmission Vegetation Management Program Project 2007-07	
Request Date Revised Date	January 9, 2007 April 2, 2007

SAR Requestor Information		**SAR Type** (*Check a box for each one that applies.*)
Name Richard Dearman	☐	New Standard
Primary Contact Richard Dearman	☒	Revision to existing Standard
Telephone (256) 851-3523 Fax	☐	Withdrawal of existing Standard
E-mail redearman@tva.gov	☐	Urgent Action

Purpose / Industry Need (Describe the purpose of the standard — what the standard will achieve in support of reliability.)

The purpose of revising this standard is to:

1. Provide an adequate level of reliability for the North American electric transmission system – by verifying that the standard is complete and that its requirements are set at an appropriate level to ensure reliability.
2. Incorporate other general improvements described in the attached Standard Review Guidelines to bring it into conformance with the latest version of the Reliability Standard Development Procedure and the ERO Sanctions Guidelines.
3. Consider comments received from ERO regulatory authorities and stakeholders, as noted in the attached review sheets.
4. Satisfy the standards procedure requirement for five-year review of the standards.

Detailed Description

This is a new standard that was approved in 2006. It has some 'fill-in-the-blank' components to eliminate. In addition, the following comments submitted by FERC and stakeholders need to be addressed in the refinement of the standard:

FERC Order 693 items

1. To address the issue regarding applicability:
   - The Standard DT shall work with the reliability entities and the ERO to collect and make available to the FERC, a list of critical lower voltage transmission lines. (Refer to Applicability 4.3 section of the standard.)
     - The standard DT may consider other criteria in determining applicability of the standard to sub 200kV lines.
2. To address the issue of clearances for lines on both federal and non-federal lands:
   - The standard drafting team shall collect and analyze outage data then consider defining clearances needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal and non-federal land.
3. To consider revising the definition of right of way to encompass required clearance areas.
4. To review the suitability of IEEE 516-2003 standard for minimum vegetation clearance.

Procedural items

5. Re-format standard to bring it into conformance with the latest version of the Reliability Standard Development Procedure and the ERO Sanctions Guidelines.
6. Remove references to RRO in the standard and substitute a responsible entity.
7. Add compliance elements such as time horizons, and violation severity levels.

Stakeholder items

8. The Standard DT shall prepare technical reference material such as a "white paper" to aid in understanding the technical basis for the standard.
9. The Standard DT shall review reporting criteria for Category 3 outages in the proposed technical reference material and may remove the reporting requirement of Category 3 outages in R.3 and R.4.
10. The Standard DT shall consider deleting requirement R.4.
11. The Standard DT will review the reporting exemptions to include all category outages under major disasters in Requirement R3.2.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced Interchange Schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area..
☐	Resource Planner	Develops a (>one year) plan for the resource adequacy of specific loads within a Planning Coordinator Area.
☐	Transmission Planner	Develops a (>one year) plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator Area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and all necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission (and related reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☐	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all the following Market Interface Principles? *(Select "yes" or "no" from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	**Explanation**

Related SARs

SAR ID	**Explanation**

Regional Differences

Region	**Explanation**
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Standard Review Guidelines

Applicability

Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose

Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements

Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability

Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations

Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness

Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance

In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?

Clear Language

Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality

Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements

In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.) should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.

Consistent Terminology

To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature;

or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Time Horizon

The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- Long-term Planning — a planning horizon of one year or longer.
- Operations Planning — operating and resource plans from day-ahead up to and including seasonal.
- Same-day Operations — routine actions required within the timeframe of a day, but not real-time.
- Real-time Operations — actions required within one hour or less to preserve the reliability of the bulk electric system.
- Operations Assessment — follow-up evaluations and reporting of real time operations.

Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. ('Violation severity levels' replace existing 'levels of non-compliance.') The violation severity levels may be applied for each requirement or combined to cover multiple requirements, as long as it is clear which requirements are included.

The violation severity levels should be based on the following definitions:

- Lower: mostly compliant with minor exceptions — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
- Moderate: mostly compliant with significant exceptions — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.
- High: marginal performance or results — The responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.
- Severe: poor performance or results — The responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

Compliance Monitor

Replace, 'Regional Reliability Organization' with 'Regional Entity'.

Fill-in-the-blank Requirements

Do not include any 'fill-in-the-blank' requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization

Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates

Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan.

Associated Documents

If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, 'Associated Documents'.

Functional Model Version 3

Review the requirements against the latest descriptions of the responsibilities and tasks assigned to functional entities as provided in pages 13 through 53 of the draft Functional Model Version 3.

Standard Authorization Request Form

~~Title of Proposed Standard~~ Revisions to FAC-003-1 Transmission Vegetation Management Program Project 2007-07	
Request Date	January 9, 2007
Revised Date	April 2, 2007

SAR Requestor Information	SAR Type (*Check a box for each one that applies.*)	
Name Richard ~~Schneider (To be replaced by SAR DT Chair when the SAR DT is appointed)~~Dearman	☐	New Standard
Primary Contact Richard ~~Schneider~~Dearman	☒	Revision to existing Standard
Telephone ~~609-452-8060~~(256) 851-3523 Fax	☐	Withdrawal of existing Standard
~~E-mail Richard.schneider@nerc.net~~E-mail redearman@tva.gov	☐	Urgent Action

Purpose / Industry Need (Describe the purpose of the standard — what the standard will achieve in support of reliability.)

The purpose of revising this standard is to:

1. Provide an adequate level of reliability for the North American ~~bulk power systems -~~electric transmission system – by verifying that the standard is complete and ~~the~~that its requirements are set at an appropriate level to ensure reliability.

~~2.Ensure it is enforceable as a mandatory reliability standard with financial penalties - the applicability to bulk power system owners, operators, and users, and as appropriate particular classes of facilities, is clearly defined; the purpose, requirements, and measures are results-focused and unambiguous; the consequences of violating the requirements are clear.~~

2. Incorporate other general improvements described in the attached Standard Review Guidelines to bring it into conformance with the latest version of the Reliability Standard Development Procedure and the ERO Sanctions Guidelines.

3. Consider comments received from ERO regulatory authorities and stakeholders, as noted in the attached review sheets.

4. Satisfy the standards procedure requirement for five-year review of the standards.

~~Brief~~Detailed Description

This is a new standard that was approved in 2006. It has some 'fill-in-the-blank' components to eliminate. In addition, the following comments submitted by FERC and stakeholders need to be addressed in the refinement of the standard:

FERC ~~NOPR~~Order 693 items

~~- Develop a minimum vegetation inspection cycle that allows variation for physical differences, as discussed above; and~~

~~- Remove the applicability to transmission lines operated at 200 kV and above so that the Reliability Standard applies to Bulk-Power System transmission lines that have an impact of reliability as determined by the ERO.~~

~~**FERC staff report**~~

~~- Objections to use of IEEE standard~~

~~**Stakeholder Comments**~~

~~- RA vs. RRO~~

~~- Too weak on compliance~~

~~- Format inconsistencies~~

1. ~~The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.~~To address the issue regarding applicability:
   - The Standard DT shall work with the reliability entities and the ERO to collect and make available to the FERC, a list of critical lower voltage transmission lines. (Refer to Applicability 4.3 section of the standard.)
     - The standard DT may consider other criteria in determining applicability of the standard to sub 200kV lines.
2. To address the issue of clearances for lines on both federal and non-federal lands:
     - The standard drafting team shall collect and analyze outage data then consider defining clearances needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal and non-federal land.
3. To consider revising the definition of right of way to encompass required clearance areas.
4. To review the suitability of IEEE 516-2003 standard for minimum vegetation clearance.

Procedural items

5. Re-format standard to bring it into conformance with the latest version of the Reliability Standard Development Procedure and the ERO Sanctions Guidelines.
6. Remove references to RRO in the standard and substitute a responsible entity.
7. Add compliance elements such as time horizons, and violation severity levels.

Stakeholder items

8. The Standard DT shall prepare technical reference material such as a "white paper" to aid in understanding the technical basis for the standard.
9. The Standard DT shall review reporting criteria for Category 3 outages in the proposed technical reference material and may remove the reporting requirement of Category 3 outages in R.3 and R.4.
10. The Standard DT shall consider deleting requirement R.4.
11. The Standard DT will review the reporting exemptions to include all category outages under major disasters in Requirement R3.2.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Reliability Coordinator	~~Ensures~~Responsible for the real-time operating reliability of ~~the bulk transmission system within~~ its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area~~. This is the highest reliability authority.~~ view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within ~~its metered boundary~~a Balancing Authority Area and supports ~~system~~interconnection frequency in real time.
☐	Interchange Authority	~~Authorizes~~Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced Interchange Schedules~~.~~ between Balancing Authority Areas.
☐	Planning ~~Authority~~Coordinator	~~Plans the Bulk Electric System.~~Assesses the longer-term reliability of its Planning Coordinator Area..
☐	Resource Planner	Develops a ~~long-term~~ (>one year) plan for the resource adequacy of specific loads within a Planning ~~Authority area.~~Coordinator Area.
☐	Transmission Planner	Develops a ~~long-term~~ (>one year) plan for the reliability of ~~transmission systems~~the interconnected Bulk Electric System within its portion of the Planning ~~Authority area.~~Coordinator Area.
☐	Transmission Service Provider	~~Provides~~Administers the transmission tariff and provides transmission services ~~to qualified market participants~~ under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	~~Operates and maintains the transmission facilities, and executes switching orders.~~Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	~~Provides and operates the "wires" between the transmission system and the customer.~~Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation ~~unit(s).~~facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and ~~performs the functions of supplying energy and Interconnected Operations Services.~~reactive power.
☐	Purchasing-Selling Entity	~~The function of purchasing~~Purchases or ~~selling~~sells energy, capacity, and all necessary ~~Interconnected Operations Services~~reliability-related services as required.
☐	Market Operator	~~Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.~~Interface point for reliability functions with commercial functions.

☐	Load-Serving Entity	Secures energy and transmission (and related ~~generation~~reliability-related services) to serve the ~~end user.~~End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☐	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all the following Market Interface Principles? *(Select "yes" or "no" from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Regional Differences

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Standard Review Guidelines

Applicability
Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose
Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements
Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability
Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations
Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness
Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance

In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?

Clear Language
Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality
Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements
In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.) should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.

Consistent Terminology
To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature;

or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

~~Mitigation~~ Time Horizon

The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. (‘Violation severity levels’ replace existing ‘levels of non-compliance.’) The violation severity levels may be applied for each requirement or combined to cover multiple requirements, as long as it is clear which requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
- **Moderate: mostly compliant with significant exceptions** — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.

- **High: marginal performance or results** — The responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.
- **Severe: poor performance or results** — The responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

Compliance Monitor
Replace, 'Regional Reliability Organization' with '~~Electric Reliability Organization'~~Regional Entity'.

Fill-in-the-blank Requirements
Do not include any 'fill-in-the-blank' requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization
Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates
Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan.

Associated Documents
If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, 'Associated Documents'.

Functional Model Version 3
Review the requirements against the latest descriptions of the responsibilities and tasks assigned to functional entities as provided in pages 13 through 53 of the draft Functional Model Version 3.

Maureen E. Long
Standards Process Manager

April 10, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: Comment Period Opens

The Standards Committee (SC) announces the following standards actions:

SAR for Transmission Vegetation Management (Project 2007-07) Posted for 30-day Comment Period April 10–May 9, 2007

The SAR for Project 2007-07 proposes modifying the Vegetation Management Standard FAC-003-1 to address concerns raised by FERC and stakeholders and to bring the standard into conformance with the latest version of the Reliability Standards Development Procedure and the ERO Sanctions Guidelines. Please use the comment form to provide comments on the second draft of this SAR.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Please use this form to submit comments on the draft Transmission Vegetation Management SAR. Comments must be submitted by **May 9, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words **"Vegetation Management SAR"** in the subject line. If you have questions please contact Harry Tom at Harry.Tom@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

The SAR drafting team considered the comments submitted in response to the first posting of the SAR as well as the FERC Order 693 in preparing the revised SAR to modify FAC-003-1 — Transmission Vegetation Management.

The SAR drafting team modified the SAR to state more specifically that the revisions to the standard need to incorporate the compliance program elements of time horizons and violation severity levels to bring FAC-003-1 into conformance with the latest version of the Reliability Standard Development Procedure and the ERO Sanctions Guidelines.

The FERC has urged further industry consideration of a number of issues and these have been listed in the revised SAR as items to address during using standards development process to refine FAC-003-1. The SAR drafting team consensus is that a modification to FAC-003-1 to address the aforementioned items is warranted.

Please review the changes made to the Vegetation Management SAR and then respond to the questions on the following pages. Please e-mail your comments to sarcomm@nerc.net with the subject “Vegetation Management SAR” by **May 9, 2007.**

You need not answer all questions. Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.

The SAR drafting team considered stakeholder comments on the first draft of this SAR and the FERC Order 693 in preparing the second draft of the SAR to modify FAC-003-1 — Transmission Vegetation Management.

The SAR drafting team modified the SAR to clarify that FAC-003-1 needs to add time horizons and violation severity levels to bring the standard into conformance with the latest version of the Reliability Standards Development Procedure and the ERO Sanctions Guidelines. (Time Horizons and Violation Severity Levels are both elements used to determine an appropriate sanction for violation of a standard.)

The SAR drafting team also modified the SAR to clarify that the scope of revisions to this standard will include addressing the issues raised by FERC in Order 693, including the following:

- Consideration of minimum clearances needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal land and non-federal land
- Revisions to the definition of ‘right of way’ to encompass required clearance areas
- Review of the suitability of IEEE Standard 516-2003 for minimum vegetation clearance

Several commenters indicated that the reporting requirements may need revision and the SAR was revised to include consideration of modifications to the reporting requirements.

The SAR drafting team consensus is that modification of FAC-003-1 to address the aforementioned items is needed to ensure reliability of the bulk power system.

1. **Do you agree there is a reliability need for the proposed modifications and review of the standard?**

   ☐ Yes

   ☐ No

   Comments:

2. **If you are a transmission owner, have you been provided a list from a Reliability Entity (formerly RRO) of sub 200kV critical transmission lines that must comply with FAC-003-1?**

   ☐ Yes

   ☐ No

   Comments:

3. **If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.**

   ☐ Yes

   ☐ No

   Comments:

4. **Are there any other comments regarding the standard, its possible modifications or the SAR?**

   ☐ Yes

   ☐ No

   Comments:

Please use this form to submit comments on the draft Transmission Vegetation Management SAR. Comments must be submitted by **May 9, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words **"Vegetation Management SAR"** in the subject line. If you have questions please contact Harry Tom at Harry.Tom@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Thad K. Ness	
Organization:	American Electric Power	
Telephone:	614-716-2053	
E-mail:	tkness@aep.com	
NERC Region		**Registered Ballot Body Segment**
☒ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☒ **SPP**	☐	7 — Large Electricity End Users
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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

The SAR drafting team considered the comments submitted in response to the first posting of the SAR as well as the FERC Order 693 in preparing the revised SAR to modify FAC-003-1 — Transmission Vegetation Management.

The SAR drafting team modified the SAR to state more specifically that the revisions to the standard need to incorporate the compliance program elements of time horizons and violation severity levels to bring FAC-003-1 into conformance with the latest version of the Reliability Standard Development Procedure and the ERO Sanctions Guidelines.

The FERC has urged further industry consideration of a number of issues and these have been listed in the revised SAR as items to address during using standards development process to refine FAC-003-1. The SAR drafting team consensus is that a modification to FAC-003-1 to address the aforementioned items is warranted.

Please review the changes made to the Vegetation Management SAR and then respond to the questions on the following pages. Please e-mail your comments to sarcomm@nerc.net with the subject “Vegetation Management SAR” by **May 9, 2007.**

You need not answer all questions. Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.

The SAR drafting team considered stakeholder comments on the first draft of this SAR and the FERC Order 693 in preparing the second draft of the SAR to modify FAC-003-1 — Transmission Vegetation Management.

The SAR drafting team modified the SAR to clarify that FAC-003-1 needs to add time horizons and violation severity levels to bring the standard into conformance with the latest version of the Reliability Standards Development Procedure and the ERO Sanctions Guidelines. (Time Horizons and Violation Severity Levels are both elements used to determine an appropriate sanction for violation of a standard.)

The SAR drafting team also modified the SAR to clarify that the scope of revisions to this standard will include addressing the issues raised by FERC in Order 693, including the following:

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- Review of the suitability of IEEE Standard 516-2003 for minimum vegetation clearance

Several commenters indicated that the reporting requirements may need revision and the SAR was revised to include consideration of modifications to the reporting requirements.

The SAR drafting team consensus is that modification of FAC-003-1 to address the

1. **Do you agree there is a reliability need for the proposed modifications and review of the standard?**

☐ Yes

☒ No

Comments: AEP believes that the current standard (when thoroughly read and understood) is completely adequate to maintain a reliable transmission system with minimum risk of vegetation-related outages.

2. **If you are a transmission owner, have you been provided a list from a Reliability Entity (formerly RRO) of sub 200kV critical transmission lines that must comply with FAC-003-1?**

☒ Yes

☒ No

Comments: Of the three regions in which AEP has transmission facilities, only one RE has provided a listing of sub-200 kV facilities of what we consider applicable under this standard.

3. **If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.**

☒ Yes

☐ No

Comments: For Clearance 1, AEP has chosen to use the minimum approach distances set forth in ANSI Tree Care Standard Z133.1 (rev. October 2000) for persons other than qualified line-clearance arborists and qualified line-clearance arborist trainees. For Clearance 2, AEP utilizes the Z133.1 minimum approach distances for qualified line clearance arborists and qualified line-clearance arborist trainees.

4. **Are there any other comments regarding the standard, its possible modifications or the SAR?**

☒ Yes

☐ No

Comments: The SAR directs the SDT to collect and analyze outage data as part of an effort to define clearances for transmission lines on federal and non-federal lands. AEP believes that the analysis of outage data will be meaningless and unproductive. The SAR directive presupposes a cause-and-effect relationship between vegetation-related outages and federal/non-federal land status. On the contrary, AEP believes that vegetation-related data is more indicative of the effectiveness of the utility's VM program, in spite of onerous and inordinately expensive measures required on federal lands.

Please use this form to submit comments on the draft Transmission Vegetation Management SAR. Comments must be submitted by **May 9, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words **"Vegetation Management SAR"** in the subject line. If you have questions please contact Harry Tom at Harry.Tom@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name: Mary Hetz		
Organization: Ameren		
Telephone: 314-554-3633		
E-mail: Mhetz@ameren.com		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
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	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: Ameren Vegetation Management Department

Lead Contact: **Ray Wiesehan**

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

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Please review the changes made to the Vegetation Management SAR and then respond to the questions on the following pages. Please e-mail your comments to sarcomm@nerc.net with the subject "Vegetation Management SAR" by **May 9, 2007.**

You need not answer all questions. Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

The SAR drafting team considered stakeholder comments on the first draft of this SAR and the FERC Order 693 in preparing the second draft of the SAR to modify FAC-003-1 — Transmission Vegetation Management.

The SAR drafting team modified the SAR to clarify that FAC-003-1 needs to add time horizons and violation severity levels to bring the standard into conformance with the latest version of the Reliability Standards Development Procedure and the ERO Sanctions Guidelines. (Time Horizons and Violation Severity Levels are both elements used to determine an appropriate sanction for violation of a standard.)

The SAR drafting team also modified the SAR to clarify that the scope of revisions to this standard will include addressing the issues raised by FERC in Order 693, including the following:

- Consideration of minimum clearances needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal land and non-federal land
- Revisions to the definition of 'right of way' to encompass required clearance areas
- Review of the suitability of IEEE Standard 516-2003 for minimum vegetation clearance

Several commenters indicated that the reporting requirements may need revision and the SAR was revised to include consideration of modifications to the reporting requirements.

The SAR drafting team consensus is that modification of FAC-003-1 to address the aforementioned items is needed to ensure reliability of the bulk power system.

1. **Do you agree there is a reliability need for the proposed modifications and review of the standard?**

   ☐ Yes

   ☐ No

   Comments:

2. **If you are a transmission owner, have you been provided a list from a Reliability Entity (formerly RRO) of sub 200kV critical transmission lines that must comply with FAC-003-1?**

   ☐ Yes

   ☐ No

   Comments:

3. **If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.**

   ☐ Yes

   ☐ No

   Comments:

4. **Are there any other comments regarding the standard, its possible modifications or the SAR?**

   ☒ Yes

   ☐ No

   Comments: Ameren does not agree that each of 11 items listed in the SAR are necessary to improve reliability. The following comments are offered for each of the 11 items identified in the SAR detail description:

   1. Standard Applicability:

   Ameren disagrees with revising the 200 kV threshold for determining facilities subject to this standard. Extending the requirements to lines other than those >200kV will dilute the focus on those lines that impact grid reliability and shift attention to facilities, <200kV. Utilities generally have an incentive to maintain reliability on lines less than 200kV. State commissions and customer expections for reliable service provide this incentive. While many facilities above 200kV directly support customer load, transmission lines below 200kV primarily support customer load, and interruptions to those facilities reduces load on the grid.

   The majority of transmission facilities below 200 kV also have significantly different design/construction/operating characteristics and have not been cited as impacting bulk power system reliability. For example, the Final Report on the August 14, 2003 Blackout in the United states and Canada: Causes and Recommendations April 2004 by the U.S.- Canada Power System Outage Task Force and all referenced major blackouts (pages 103-115) in that report, cited only outages which involved vegetation at line voltages above 200kV. Generally applying requirements that are appropriate for >200kV lines to lines less than 200kV will result in significant documentation and reporting of items such as restrictions, mitigation plans, off right-of-way vegetation-related outage investigation/ information and other issues, all of which dilutes the focus on lines that directly impact bulk power system reliability.

Revising the standard to use general criteria or broad language for defining "Bulk Power System" transmission lines covered by the standard is a “one size fits all” approach. If that approach were taken, the standard would cover a significant number of transmission lines that have no direct impact on bulk power system reliability under standard planning/operating conditions, resulting in a significant cost burden for electric customers without improving “grid” reliability. Ameren believes that the applicability provision of the standard should focus attention of the standard only on the transmission lines below 200kV that directly impact “Bulk Power System” reliability, as the current version requires.

Ameren recognizes some validity in the Commission’s concern, Ameren recommends that the applicability provision of this standard should be revised only if existing system design, planning or operating reliability criteria and parameters are considered as a basis for defining the applicability of the standard. Ameren recommends each Regional Entity (RE) determine applicability of FAC-003 to those lines within the region that are between 100kV and 200KV, if, and only if, they are identified as operationally significant elements of Interconnection Reliability Operating Limits (“IROLs”). That is, any facility below 200kV that by itself would cause an Interconnected Reliability Limit Violation should the facility
be outaged.

2. Issue of Clearances (Federal vs Non-Federal Lands):

FAC-003-1 presently requires the transmission owner (TO) “identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway.” The intent of this requirement is to ensure adequate clearances to prevent vegetation related outages. Ameren believes that only the TO has the technical information required to determine the clearances that are necessary at the time of VM work and that any “federal lands exemption” to clearances will result in inadequate clearances for the existing conditions. Consistency in application of the TO’s clearance requirements, not exceptions, is the only assurance in providing a uniform and reliable electrical system to meet the nation’s current and future energy demands.
Any exception for a case by case clearance approach to determine vegetation management activities/clearances on Federal lands will continue to drive inconsistency and/or delays associated with vegetation management decisions being driven by diverse vegetation management practices/beliefs and staff changes at the local level of Federal agencies. Vegetation-related outages have occurred on Federal lands as a result of this case by case approach, and if “Bulk Power Transmission System” lines continue to be addressed on a “case by case” basis on National Forest Service (or any other Federal lands), those lines will potentially be subject to a higher risk for vegetation-related outages, resulting in reduced reliability for the “Bulk Power System”.

Ameren believes that reliability of the “Bulk Power System” should have the same focus on Federal and private lands and that the EEI MOU with federal agencies is the appropriate vehicle for TO's to identify clearance variances on Ferderal lands, not exemption language in the standard. The standard should not be used as a mechanism by federal agencies to impose variances to proven vegetation management practices and clearances.

3. Defining Right-of-Way:

Ameren agrees that it is appropriate to further address the definition of “right-of-way”. Corridor widths beyond design clearance requirements have been acquired for a variety of reasons in the past; future use, property line buffers, etc. Vegetation in those areas that would normally fall outside of the area necessary for operation of the facility should not be considered or treated different than vegetation that is outside of a defined easement/permit area that is designed for the reliable operation of an existing single line corridor.

4. IEEE Standard for Minimum Clearances:

Ameren disagrees with objections to the use of the IEEE 516-2003 clearance as the minimum acceptable distances for “Clearance 2”. The IEEE 516-2003 tables are appropriate for defining the minimum acceptable clearances to prevent flashover between conductors and vegetation under all rated electrical operating conditions. FERC staff references ANSI Z-133 which is a safety standard that addresses worker safety as well as the safety of the general public. As such, the purpose of ANSI Z-133 is to address worker safety and is not focused on transmission line reliability, which is the purpose of FAC-003-1. OSHA, NESC and other related safety standards have clearances in excess of IEEE 516-2003. Those clearances are clearly focused on safety issues and will still apply to other aspects of design and operation of electric facilities (such as public and worker safety) but are not appropriate to be referenced in a vegetation management reliability standard.

5/6/7. Procedural Items:

Ameren agrees that the procedural items related to formatting RRO references and additional compliance elements should be addressed by the standard drafting team.

8. Technical Reference Materials:

Ameren agrees that a “white paper” that defines the technical basis for the standard is appropriate to avoid the potential for differences in interpretation of the standard’s requirements during the various region's audit processes.

9. Category 3 Outages:

Since the right to control off right-of-way vegetation is generally beyond control of the transmission owner Ameren believes that the reporting of category 3 outages should be removed from the requirements.

10. Requirement R4:

Ameren believes that requirement R4 should be deleted from the standard, based on the ERO formation and the process for delegation of authority to the regional entities.

11. Reporting Exemptions:

Ameren believes that the reporting requirement exemptions for natural disasters should include all categories of outages. It would, for example, be difficult, without delaying restoration efforts, to determine if the vegetation from high winds, hurricanes, tornadoes, etc. is from on or off the "right-of-way".

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	John R. Kellum, Jr.	
Organization:	CenterPoint Energy Houston Electric, LLC (CenterPoint Energy)	
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NERC Region		**Registered Ballot Body Segment**
☒ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

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Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

The SAR drafting team considered the comments submitted in response to the first posting of the SAR as well as the FERC Order 693 in preparing the revised SAR to modify FAC-003-1 — Transmission Vegetation Management.

The SAR drafting team modified the SAR to state more specifically that the revisions to the standard need to incorporate the compliance program elements of time horizons and violation severity levels to bring FAC-003-1 into conformance with the latest version of the Reliability Standard Development Procedure and the ERO Sanctions Guidelines.

The FERC has urged further industry consideration of a number of issues and these have been listed in the revised SAR as items to address during using standards development process to refine FAC-003-1. The SAR drafting team consensus is that a modification to FAC-003-1 to address the aforementioned items is warranted.

Please review the changes made to the Vegetation Management SAR and then respond to the questions on the following pages. Please e-mail your comments to sarcomm@nerc.net with the subject "Vegetation Management SAR" by **May 9, 2007.**

You need not answer all questions. Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

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The SAR drafting team also modified the SAR to clarify that the scope of revisions to this standard will include addressing the issues raised by FERC in Order 693, including the following:

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- Revisions to the definition of 'right of way' to encompass required clearance areas
- Review of the suitability of IEEE Standard 516-2003 for minimum vegetation clearance

Several commenters indicated that the reporting requirements may need revision and the SAR was revised to include consideration of modifications to the reporting requirements.

The SAR drafting team consensus is that modification of FAC-003-1 to address the aforementioned items is needed to ensure reliability of the bulk power system.

1. **Do you agree there is a reliability need for the proposed modifications and review of the standard?**

   ☐ Yes

   ☒ No

   Comments: CenterPoint Energy does not agree that a revision to the TVM standard is necessary from a reliability standpoint, and believes that the existing TVM standard is adequate for that purpose.

2. **If you are a transmission owner, have you been provided a list from a Reliability Entity (formerly RRO) of sub 200kV critical transmission lines that must comply with FAC-003-1?**

   ☐ Yes

   ☒ No

   Comments:

3. **If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.**

   ☒ Yes

   ☐ No

   Comments: CenterPoint Energy has developed a methodology to determine clearance 1 and clearance 2 as described in FAC-003-1 R1.2.1 and R1.2.2. This methodology is included in a document titled "Specification for Transmission Vegetation Management Program" dated February 2007. Section 5.1 of that document covers NERC Clearance 1, and Section 5.2 covers NERC Clearance 2. Text and Tables from both Sections 5.1 and 5.2 are shown below:

   5.1 NERC CLEARANCE 1

   5.1.1 The appropriate clearance to conductors at the time of vegetation management work is established as Clearance 1 in accordance with NERC Standard FAC-003-1 Requirement R1.2.1.

   5.1.2 Clearance 1 is determined by considering transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, the effects of wind velocities on conductor sway, and the anticipated average growth rate of the prevalent tree species within the Company’s service area over a 5-year period.

   5.1.2.1 The minimum clearance distance of IEEE Standard 516-2003 Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap, is a component of Clearance 1.

   5.1.3 Table 5.1 contains the horizontal clearance components and nominal values for Clearance 1, and Table 5.2 contains the vertical clearance components and nominal values for Clearance 1.

Table 5.1
NERC Clearance 1: Horizontal Clearance, feet
Horizontal Clearance Component, Nominal Voltage p-p

	69kV	138kV	345kV
Electrical Clearance (1)	2.46	2.95	4.40
Average 5-Year Horizontal Tree Growth	12.00	12.00	12.00
Average Mid-span Conductor Sway (2)	5.98	8.13	10.04
Total	20.44	23.08	26.44
Nominal Horizontal Value (3)	20	23	26

(1) Based on IEEE 516-2003 Table 5 for 69kV & 138kV and Table 7 for 345kV
(2) Based on NESC C2-2007 Rule 233A(1)
(3) May be reduced for site specific tree species or conductor span configuration but not less than Clearance 2.

Table 5.2
NERC Clearance 1: Vertical Clearance, feet
Vertical Clearance Component, Nominal Voltage p-p

	69kV	138kV	345kV
Electrical Clearance (1)	2.46	2.95	4.40
Average 5-Year Vertical Tree Growth	15.75	15.75	15.75
Average Conductor Final Sag Increase (2)	7.52	9.01	10.24
Total	25.73	27.71	30.39
Nominal Vertical Value (3)	26	28	30

(1) Based on IEEE 516-2003 Table 5 for 69kV & 138kV and Table 7 for 345kV
(2) Based on NESC C2-2007 Rule 233A(1)
(3) May be reduced for site specific tree species or conductor span configuration but not less than Clearance 2.

5.2 NERC CLEARANCE 2

5.2.1 The minimum radial clearance to prevent flashover between vegetation and conductors is established as Clearance 2 in accordance with NERC Standard FAC-003-1 Requirement R1.2.2.

5.2.2 Clearance 2 is determined by considering transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Clearance 2 is a radial clearance, so the vertical component and the horizontal component are both calculated, and the largest clearance is selected as the prevailing clearance for Clearance 2.

5.2.2.1 The minimum clearance distance of IEEE Standard 516-2003 Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap, is a component of Clearance 2.

5.2.3 Table 5.3 contains the horizontal clearance component, Table 5.4 contains the vertical clearance component, and Table 5.5 contains the prevailing nominal values for Clearance 2.

Table 5.3

Horizontal Clearance Component, feet
Horizontal Clearance Component, Nominal Voltage p-p

	69kV	138kV	345kV
Electrical Clearance (1)	2.46	2.95	4.40
Average Mid-span Conductor Sway (2)	5.98	8.13	10.04
Total	8.44	11.08	14.44
Nominal Horizontal Value (3)	8	11	14

(1) Based on IEEE 516-2003 Table 5 for 69kV & 138kV and Table 7 for 345kV
(2) Based on NESC C2-2007 Rule 233A(1)
(3) May be reduced for site specific tree species or conductor span configuration but not less than Clearance 2.

Table 5.4

Vertical Clearance Component, feet
Vertical Clearance Component, Nominal Voltage p-p

	69kV	138kV	345kV

Electrical Clearance (1)	2.46	2.95	4.40
Average Conductor Final Sag Increase (2)	7.52	9.01	10.24
Total	9.98	11.96	14.64
Nominal Vertical Value (3)	10	12	15

(1) Based on IEEE 516-2003 Table 5 for 69kV & 138kV and Table 7 for 345kV
(2) Based on NESC C2-2007 Rule 233A(1)
(3) May be reduced for site specific tree species or conductor span configuration but not less than Clearance 2.

Table 5.5

NERC Clearance 2: Minimum Radial Clearance to Prevent Flashover, feet
Nominal Voltage p-p

69kV	138kV	345kV
10	12	15

4. Are there any other comments regarding the standard, its possible modifications or the SAR?

☐ Yes

☒ No

Comments:

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Weston J Davis	
Organization:	Central Maine Power an Energey East Company	
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E-mail:	Weston.Davis@cmpco.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
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Additional Member Name	Additional Member Organization	Region*	Segment*

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The FERC has urged further industry consideration of a number of issues and these have been listed in the revised SAR as items to address during using standards development process to refine FAC-003-1. The SAR drafting team consensus is that a modification to FAC-003-1 to address the aforementioned items is warranted.

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You need not answer all questions. Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

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The SAR drafting team also modified the SAR to clarify that the scope of revisions to this standard will include addressing the issues raised by FERC in Order 693, including the following:

- Consideration of minimum clearances needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal land and non-federal land
- Revisions to the definition of 'right of way' to encompass required clearance areas
- Review of the suitability of IEEE Standard 516-2003 for minimum vegetation clearance

Several commenters indicated that the reporting requirements may need revision and the SAR was revised to include consideration of modifications to the reporting requirements.

The SAR drafting team consensus is that modification of FAC-003-1 to address the aforementioned items is needed to ensure reliability of the bulk power system.

1. **Do you agree there is a reliability need for the proposed modifications and review of the standard?**

   ☐ Yes

   ☒ No

   Comments: The current Vegetation Management Standard FAC-003-1 has been crafted in such a way as to provide crisp measurable standards that when followed will provide a high level of power quality for the bulk power delivery system. However, clearances between conductors and trees required to prevent tree related power outages must be consistent with each utility's established standards and if a transmission line passes through federal, state or locally managed areas this line placement should not impact the established clearances. Utilities should not be expected to negotiate clearances with multiple land managers.

   The IEEE 516 – 2003 table is an acceptable table to use as the minimum clearance to prevent a flash over and outages. FAC-003-1 is designed to be a reliability standard and the industry adheres to OSHA and ANSI standards to protect workers and the public.
   The IEEE 516 – 2003 table lists appropriate distances that should be used to measure compliance. The standard should continue to provide the flexibility for utility managers to increase "Clearance 2".

   The definition for right-of-way should be clarified to include only the area that is cleared and included as routine maintenance.

   We agree that there is a need to establish time horizons and clarify violation levels.

2. **If you are a transmission owner, have you been provided a list from a Reliability Entity (formerly RRO) of sub 200kV critical transmission lines that must comply with FAC-003-1?**

   ☐ Yes

   ☒ No

   Comments: The "Northeast Power Coordinating Council Facilities Notification List" may not be the correct list to be used for this standard. FAC- 003-1 should set a clear expectation the each Regional Entity will provide their transmission owners a list of critical lines including any that may be less that 200KV. Will provide list once released from NPCC.

3. **If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.**

   ☐ Yes

   ☒ No

   Comments: The clearance 2 was taken directly from IEEE Table 516 – 2003. Clearance 1 is based on "Appendix C – ISO New England Right of way Vegetation Management Standard".

4. Are there any other comments regarding the standard, its possible modifications or the SAR?

☒ Yes

☐ No

Comments: The standard FAC-003-1 is intended to create a frame work that will ensure a uniform level of reliability and at the same time must allow transmission owners to meet this objective using efficient and cost effective programs. To this end utilities must have the ability to implement “Clearance 1” distances consistently throughout their service areas.

The standard should remain focused only on 200 KV and above lines or lines listed as critical by the Regional Entity.

Inspection cycles are sufficient as listed the current version and allow flexibility to meet local variability in growth rates and other conditions. Concerns with inspection cycle length can be addressed in the compliance area

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name: CJ Ingersoll		
Organization: CECD		
Telephone: 713-332-2906		
E-mail: c.j.ingersoll@constellation.com		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
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The SAR drafting team consensus is that modification of FAC-003-1 to address the aforementioned items is needed to ensure reliability of the bulk power system.

1. **Do you agree there is a reliability need for the proposed modifications and review of the standard?**

   ☒ Yes

   ☐ No

   Comments: Modifications to capture the Commissions concerns must be addressed therefore these actions are appropriate.

2. **If you are a transmission owner, have you been provided a list from a Reliability Entity (formerly RRO) of sub 200kV critical transmission lines that must comply with FAC-003-1?**

   ☐ Yes

   ☒ No

   Comments: SERC does not currently have any sub 200 kV critical transmission lines.

3. **If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.**

   ☐ Yes

   ☐ No

   Comments:

4. **Are there any other comments regarding the standard, its possible modifications or the SAR?**

   ☒ Yes

   ☐ No

   Comments: CECD supports continuing to use the 200kV threshold for determining applicablility of vegetation management criteria. If the standard is deemed to apply to lower voltages these should only be critical lower voltage transmission facilities as determined by the Regional Entities's. CECD would also encourage the drafting team to clarify that the Vegetation Management standards are not applicable to generator interconnection facilities. In the registration process due to the NERC functional definitions, Generation Owners/Operators are required to register as Transmission Owners/Operators because of step-up transformers and other associated interconnection equipment that was not intended to be subject to the Vegetation Management program.

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	William T. Rees, Jr.	
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NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
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☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

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The SAR drafting team modified the SAR to state more specifically that the revisions to the standard need to incorporate the compliance program elements of time horizons and violation severity levels to bring FAC-003-1 into conformance with the latest version of the Reliability Standard Development Procedure and the ERO Sanctions Guidelines.

The FERC has urged further industry consideration of a number of issues and these have been listed in the revised SAR as items to address during using standards development process to refine FAC-003-1. The SAR drafting team consensus is that a modification to FAC-003-1 to address the aforementioned items is warranted.

Please review the changes made to the Vegetation Management SAR and then respond to the questions on the following pages. Please e-mail your comments to sarcomm@nerc.net with the subject "Vegetation Management SAR" by **May 9, 2007.**

You need not answer all questions. Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

The SAR drafting team considered stakeholder comments on the first draft of this SAR and the FERC Order 693 in preparing the second draft of the SAR to modify FAC-003-1 — Transmission Vegetation Management.

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The SAR drafting team also modified the SAR to clarify that the scope of revisions to this standard will include addressing the issues raised by FERC in Order 693, including the following:

- Consideration of minimum clearances needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal land and non-federal land
- Revisions to the definition of 'right of way' to encompass required clearance areas
- Review of the suitability of IEEE Standard 516-2003 for minimum vegetation clearance

Several commenters indicated that the reporting requirements may need revision and the SAR was revised to include consideration of modifications to the reporting requirements.

The SAR drafting team consensus is that modification of FAC-003-1 to address the aforementioned items is needed to ensure reliability of the bulk power system.

1. **Do you agree there is a reliability need for the proposed modifications and review of the standard?**

   ☐ Yes

   ☒ No

   Comments: I'm not convinced that the elements outlined in the proposal will improve reliability and have concerns that the proposed modifications may actually reduce the flexibility that is necessary to promote system reliability or to comply with local regulations. I would prefer to see more specifics in the proposal before supporting the modifications.

2. **If you are a transmission owner, have you been provided a list from a Reliability Entity (formerly RRO) of sub 200kV critical transmission lines that must comply with FAC-003-1?**

   ☐ Yes

   ☒ No

   Comments: The reason that we do not have a list of critical lines from the RRO may be that we do not have any lines that fit the criteria.

3. **If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.**

   ☐ Yes

   ☒ No

   Comments:

4. **Are there any other comments regarding the standard, its possible modifications or the SAR?**

   ☒ Yes

   ☐ No

   Comments: We completely disagree with the proposal to eliminate reporting or off-right-of-way tree outages. In reality, off-R/W outages can cause many of the same problems that on R/W outages do if they were to occur at the most inappropriate time. Granted that they typically do not occur at times of peak load, but they could. Moreover, many off-R/W tree outages are preventable and should be addressed before they occur.

Please use this form to submit comments on the draft Transmission Vegetation Management SAR. Comments must be submitted by **May 9, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words **"Vegetation Management SAR"** in the subject line. If you have questions please contact Harry Tom at Harry.Tom@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information		
(Complete this page for comments from one organization or individual.)		
Name:	Gene Walton	
Organization:	Dominion	
Telephone:	804-257-4770	
E-mail:	gene.walton@dom.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
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Contact Organization:

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Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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The FERC has urged further industry consideration of a number of issues and these have been listed in the revised SAR as items to address during using standards development process to refine FAC-003-1. The SAR drafting team consensus is that a modification to FAC-003-1 to address the aforementioned items is warranted.

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- Consideration of minimum clearances needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal land and non-federal land
- Revisions to the definition of 'right of way' to encompass required clearance areas
- Review of the suitability of IEEE Standard 516-2003 for minimum vegetation clearance

Several commenters indicated that the reporting requirements may need revision and the SAR was revised to include consideration of modifications to the reporting requirements.

The SAR drafting team consensus is that modification of FAC-003-1 to address the aforementioned items is needed to ensure reliability of the bulk power system.

1. **Do you agree there is a reliability need for the proposed modifications and review of the standard?**

   ☒ Yes

   ☐ No

   Comments: We support reinstating the 200kv threshold for reportable events.

2. **If you are a transmission owner, have you been provided a list from a Reliability Entity (formerly RRO) of sub 200kV critical transmission lines that must comply with FAC-003-1?**

   ☐ Yes

   ☒ No

   Comments:

3. **If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.**

   ☐ Yes

   ☐ No

   Comments:

4. **Are there any other comments regarding the standard, its possible modifications or the SAR?**

   ☒ Yes

   ☐ No

   Comments: In response to Stakeholder item #11, we do not support exempting Category 1 or Category 2 events that occur during natural disasters.

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name: Greg Rowland		
Organization: Duke Energy		
Telephone: 704-382-5348		
E-mail: gdrowlan@duke-energy.com		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
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Lead Contact:

Contact Organization:

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The FERC has urged further industry consideration of a number of issues and these have been listed in the revised SAR as items to address during using standards development process to refine FAC-003-1. The SAR drafting team consensus is that a modification to FAC-003-1 to address the aforementioned items is warranted.

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Several commenters indicated that the reporting requirements may need revision and the SAR was revised to include consideration of modifications to the reporting requirements.

The SAR drafting team consensus is that modification of FAC-003-1 to address the aforementioned items is needed to ensure reliability of the bulk power system.

1. **Do you agree there is a reliability need for the proposed modifications and review of the standard?**

   ☐ Yes

   ☒ No

   Comments: From a reliability perspective, the current standard contains appropriate requirements and measures to ensure the Transmission Owner's vegetation management program is implemented and managed to ensure the reliability of the transmission system. However the standard should be revised to address non-reliability related items that are in the SAR.

2. **If you are a transmission owner, have you been provided a list from a Reliability Entity (formerly RRO) of sub 200kV critical transmission lines that must comply with FAC-003-1?**

   ☐ Yes

   ☒ No

   Comments: The SERC region has not identified any lines below 200kV to be critical to the electrical system in the region. Since no lines have been identified as critical to the region, no list has been provided to Transmission Owners.

3. **If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.**

   ☐ Yes

   ☐ No

   Comments:

4. **Are there any other comments regarding the standard, its possible modifications or the SAR?**

   ☒ Yes

   ☐ No

   Comments: Regarding the Order 693 items, the applicability provision of the standard should focus attention of the standard only on the transmission lines 200kV and above, and those lines below 200kV that directly impact "Bulk Power System" reliability, as the current version of FAC-003 requires. Each Regional Entity (RE) must determine applicability of FAC-003 to those lines within the region that are less than 200kV. For example, transmission lines below 200kV should be considered within the scope of FAC-003 if they are identified as operationally significant elements of Interconnection Reliability Operating Limits ("IROLs"); i.e. an outage of the facility would cause an Interconnection Reliability Limit Violation.

   The Standard DT should address the issue of the necessity of maintaining consistent clearances for lines on both federal and non-federal lands.

   We agree with the use of the IEEE 516-2003 standard for for defining the minimum acceptable clearances to prevent flashover between conductors and vegetation under all rated electrical operating conditions.

We believe that the reporting requirement exemptions for natural disasters should include all categories of outages.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name: Paul D. Olivier		
Organization: Entergy Corporation		
Telephone: 504-365-3653		
E-mail: polivie@entergy.com		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
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- Revisions to the definition of 'right of way' to encompass required clearance areas
- Review of the suitability of IEEE Standard 516-2003 for minimum vegetation clearance

Several commenters indicated that the reporting requirements may need revision and the SAR was revised to include consideration of modifications to the reporting requirements.

The SAR drafting team consensus is that modification of FAC-003-1 to address the aforementioned items is needed to ensure reliability of the bulk power system.

1. Do you agree there is a reliability need for the proposed modifications and review of the standard?

☒ Yes

☐ No

Comments: The existing FAC-003-1 is flawed and needs revision.

2. If you are a transmission owner, have you been provided a list from a Reliability Entity (formerly RRO) of sub 200kV critical transmission lines that must comply with FAC-003-1?

☒ Yes

☐ No

Comments:

Yes, the Reliability Entity (SERC) has performed its duty in evaluating our transmission system. SERC has confirmed that Entergy has no lines operating below 200kV that are critical to system reliability. Entergy has received its "list," but the list is blank.

With respect to applicability, it is inappropriate to set a blunt voltage level criterion for determining which transmission lines are critical to bulk system reliability. There is no basis in engineering or in fact for voltage-based categories of applicability. Many lines operating at 200kV and higher essentially serve only local load, and there may in fact be some lines operating below 200kV where the standard should be applied. Many lines of all voltages are redundant and do not even impact local load during an outage. Therefore, the voltage criterion is overly broad.

To support this statement, Entergy supplies the following facts:

First, during the aftermath of Hurricanes Katrina and Rita, Entergy had (59) 230kV and 500kV lines out of service simultaneously. Additionally, Entergy had (85) 115kV and 161kV lines out of service simultaneously. During the aftermath of Hurricane Rita, Entergy had (41) 230kV and 500kV lines out of service simultaneously. Additionally, Entergy had (124) 115kV and 161kV lines out of service simultaneously. Dispite this overwhelming combination of simultaneous outages, no system-wide cascading blackout was initiated. Only local load was lost during restoration. This illustrates that Standard FAC-003-1, as it currently stands placing so much focus and penalty on even single-contingency outages, is overbroad, arbitrary and capricious.

Second, each year the Entergy transmission system (like all other large electric utilities) suffers numerous outages from a great number of different sources: material defects, rot and decay, animal damage, human damage, extreme wind, lightning and, vegetation. Over the years 2001 through 2006, 927 transmission lines suffered 5,688 outages from a variety of sources. Vegetation outages accounted for 7.14% of those outages. Each utility is unique, but these numbers are not unusual for a transmission system comprising 15,000 miles of line. Dispite this large number of outages, no cascading system black out has been intiated.

Finally, Entergy has had as many as 17 transmission lines outaged from a single tornado event without even losing service to local load. Standard FAC-003-1 assigns too much risk to outages in general, and too mush risk to vegetation outages in particular.

NERC and the regional reliability entities should define performance criteria that specifically define certain contingencies and certain undesireable outcomes that would classify a line as truly critical to bulk system reliability. The modeling software necessary to do this is readily available and already in use today by the Reliability Entities and their subject utilities.

If FERC has concerns about potentially devistating (albeit rare) combinations of multiple simultaneous line outage contingencies, the REs can define strict criteria for multiple contingencies. With respect to lines that result in IROLs and SOLs, these lines can also be identified with specificity, without resorting to blunt voltage distinctions.

Defining system-critical lines too broadly is actually detrimental to FERC's reliability goals. It dilutes the resources available to maintain reliability on those lines that truly affect system reliability. Utilities should employ a more focused and intelligent approach to targeted reliability. Such an approach would have benefits to the users of the transmission system and to the ratepayers that pay for it.

3. If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.

☒ Yes

☐ No

Comments:

Entergy defines four sets of clearances for vegetation approach to transmission lines.

The first set of clearances is the Vegetation Pruning Distance. This is the clearance to be achieved at the time of vegetation management work which vegetation management employees and contractors complete as part of this program. This distance varies with each line, but is set to be the EDGE OF ROW in each case. (This clearance is referred to as “Clearance 1” in the NERC Vegetation standard FAC-003-1, Cf B.R1.2.1).

The second set of clearances is the Vegetation Growth Alert Distance. This is the approach distance that triggers an alert to the Asset Management vegetation management employees that vegetation maintenance is required. Vegetation spotted on an aerial inspection that encroaches upon this clearance is noted on the inspection for future scheduling of pruning.

The third set of clearances is the Minimum Energized Pruning Distance. This is the minimum approach distance vegetation can have to energized transmission lines and still be pruned without an outage on the energized transmission line, in accordance with OSHA safety guidelines. Any vegetation that encroaches on this minimum distance must be pruned, and must be pruned during an outage on the associated transmission line.

The fourth set of clearances is the Minimum Vegetation Approach Distance. This is the absolute minimum radial approach distance to prevent flashover between vegetation and overhead ungrounded supply conductors. Under this program, vegetation should never encroach these minimum approach distances. Vegetation must be pruned prior to reaching this distance and must be pruned with an outage on the transmission line. (This distance is referred to as “Clearance 2” in the NERC vegetation standard, FAC-003-1, Cf B.R1.2.2.) These clearance distances are based upon those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (Guide for Maintenance Methods on Energized Power Lines) and as specified in Table 5.

Under this program, vegetation can encroach the Vegetation Growth Alert Distance and the Minimum Energized Pruning Distance, but it shall not encroach upon the Minimum Vegetation Approach Distance.

4. Are there any other comments regarding the standard, its possible modifications or the SAR?

☒ Yes

☐ No

Comments:

The policy to increase sanctions based on a finding of an "intentional economic decision to violate the standard" is ill-concieved:

1. Every transmission line outage that has ever occured could have been avoided if more money had been spent on SOMETHING, SOMWHERE.
2. No utility has an unlimited budget, so decisions based on risk, cost and benefit are made every day.
3. After the outage, the localized initiating cause will appear so trivial and inexpensive that it would seem that it could easily have been fixed in advance.
4. Therefore, reviewers could conclude that EVERY outage (a defacto violation of the standard), is the result of an "economic decision to violate the standard."

Economic choices are a necessary and natural part of doing business, and do not necessarily imply the existence of malicious motives or wrong-doing.

The current policy is going to create unnecessary costs to ratepayers, even to avoid inconsequential outages.

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name: Doug Hohlbaugh		
Organization: FirstEnergy Corp		
Telephone: 330-384-4698		
E-mail: hohlbaughdg@firstenergycorp.com		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
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The SAR drafting team consensus is that modification of FAC-003-1 to address the aforementioned items is needed to ensure reliability of the bulk power system.

1. **Do you agree there is a reliability need for the proposed modifications and review of the standard?**

☒ Yes

☐ No

Comments: FirstEnergy agrees that clarification on select issues will aid the intent of this NERC Standard.

2. **If you are a transmission owner, have you been provided a list from a Reliability Entity (formerly RRO) of sub 200kV critical transmission lines that must comply with FAC-003-1?**

☒ Yes

☒ No

Comments: ReliabilityFirst, the Reliability Entity (formerly the RRO) was requested to provided a list of lines below 200 kV deemed as crititical transmission lines that must comply with FAC-003-01. ReliabilityFirst responded "there are no lines below 200kV deemed as critical infrustructure".

3. **If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.**

☒ Yes

☐ No

Comments: For R1.2.1 (Clearance 1), FirstEnergy used our existing specification requirement "for minimum clearance to be achieved at locations with an easement or other restriction" to define the minimum exceptable clearance.

For R1.2.2 (Clearance 2), FirstEnergy uses the IEEE 516-2003 standard as the minimum as referenced in FAC-003-01. This is the minimum clearance under all operating conditions. FirstEnergy believes this is an appropriate definition.

4. **Are there any other comments regarding the standard, its possible modifications or the SAR?**

☒ Yes

☐ No

Comments:
The definition of Right-Of-Way requires modification to clarify it is the width required by engineering to operate the line. This may or may not be the legal Right-of-Way. (See previously submitted comments submitted by FE in Feb 2007 for more details).

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	John Tamsberg	
Organization:	Florida Power and Light	
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E-mail:	john_tamsberg@fpl.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☒ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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The SAR drafting team modified the SAR to state more specifically that the revisions to the standard need to incorporate the compliance program elements of time horizons and violation severity levels to bring FAC-003-1 into conformance with the latest version of the Reliability Standard Development Procedure and the ERO Sanctions Guidelines.

The FERC has urged further industry consideration of a number of issues and these have been listed in the revised SAR as items to address during using standards development process to refine FAC-003-1. The SAR drafting team consensus is that a modification to FAC-003-1 to address the aforementioned items is warranted.

Please review the changes made to the Vegetation Management SAR and then respond to the questions on the following pages. Please e-mail your comments to sarcomm@nerc.net with the subject “Vegetation Management SAR” by **May 9, 2007.**

You need not answer all questions. Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.

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The SAR drafting team also modified the SAR to clarify that the scope of revisions to this standard will include addressing the issues raised by FERC in Order 693, including the following:

- Consideration of minimum clearances needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal land and non-federal land
- Revisions to the definition of ‘right of way’ to encompass required clearance areas
- Review of the suitability of IEEE Standard 516-2003 for minimum vegetation clearance

Several commenters indicated that the reporting requirements may need revision and the SAR was revised to include consideration of modifications to the reporting requirements.

The SAR drafting team consensus is that modification of FAC-003-1 to address the aforementioned items is needed to ensure reliability of the bulk power system.

1. **Do you agree there is a reliability need for the proposed modifications and review of the standard?**

   ☒ Yes

   ☐ No

   Comments: FPL believes the technical portion of the standard provides adequate reliability protection to the system. FPL also recognizes the need to re-format the standard to bring it into conformance with the latest version of the Reliability Standard Development Procedure and the ERO Sanctions Guidelines, to remove references to RRO in the standard and substitute a responsible entity and, add compliance elements such as time horizons, and violation severity levels.

2. **If you are a transmission owner, have you been provided a list from a Reliability Entity (formerly RRO) of sub 200kV critical transmission lines that must comply with FAC-003-1?**

   ☒ Yes

   ☐ No

   Comments:

3. **If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.**

   ☐ Yes

   ☒ No

   Comments:

4. **Are there any other comments regarding the standard, its possible modifications or the SAR?**

   ☒ Yes

   ☐ No

   Comments: For the record FPL re-emphasixe its comments from the previous FAC 003-1 SAR.

   Requirement 3.2 exempts reporting of outages from outside the ROW when natural disasters such as tornados or hurricanes occur. Our experience with numerous hurricanes indicates that all outages during these types of events should be exempt. The focus in these situations is to get the lines back in service and restore customers. There is insufficient manpower to adequately complete the forensics necessary to determine an accurate root cause. It is not uncommon to find vegetation debris in the lines or downed trees on the ROW in this situation. In most cases it is not possible to determine the original location of these trees.

   In the compliance section of the document a transmission owner becomes non compliant with a single category 1 or 2 outage. This occurs regardless of the circumstances. A non compliant penalty for a single outage in a situation where no customers were affected and the system could not have been compromised is not reasonable. It is also not an indicator of a poorly maintained system. We agree that several Category 1 or 2 interruptions could be an indicator of neglect but one is not. We recommend that the compliance section be reviewed with this in mind.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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Organization:	Hydro-Québec TransÉnergie (HQT)	
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NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*
François Gauthier	**HQT**	**NPCC**	1
Charles Sarthou	**HQT**	**NPCC**	1

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The FERC has urged further industry consideration of a number of issues and these have been listed in the revised SAR as items to address during using standards development process to refine FAC-003-1. The SAR drafting team consensus is that a modification to FAC-003-1 to address the aforementioned items is warranted.

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The SAR drafting team consensus is that modification of FAC-003-1 to address the aforementioned items is needed to ensure reliability of the bulk power system.

1. **Do you agree there is a reliability need for the proposed modifications and review of the standard?**

   ☐ Yes

   ☒ No

   Comments: It is our belief that the Standard in its current form does provide adequate provisions and drivers to minimize vegetation related outages and eliminate the likelihood of reoccurence of the August 14, 2003 blackout. However, it is recognized that the industry needs to consolidate its view on these provisions and we support the preparation of a “white paper” that will document the rationale concerning the requirements of the standard, as well as review certain aspects of the standard that have come into question.

2. **If you are a transmission owner, have you been provided a list from a Reliability Entity (formerly RRO) of sub 200kV critical transmission lines that must comply with FAC-003-1?**

   ☐ Yes

   ☒ No

   Comments: We consider that it should be the Planning Coordinator role to determine the sub 200kV critical transmission lines and even for any transmission lines irrelevent of voltage level. For that, it should follow an impact based methodology such as the one used in NPCC.

3. **If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.**

   ☒ Yes

   ☐ No

   Comments: HQT clearance methodology is not specifically based on the value specified in Clearance 1 and Clearance 2. HQT TVMP is such organized that vegetation management work minimize costs for line clearing and brush control while preventing outages from vegetation cause. As such, staff qualifications required to work near energized facilities are less than under the absolute minimum as stipulated in IEEE 516-2003, and in most cases, the work is less labour and equipment intensive. However clearances are never less than the absolute minimum stipulated in FAC-003-1 (R1.2.2).

   The above provides the basic approach used at HQT. If the Standard Drafting Team would like a copy of the HQT approach and methodology, this could be provided.

4. **Are there any other comments regarding the standard, its possible modifications or the SAR?**

   ☒ Yes

   ☐ No

   Comments: Here are some general comments on the SAR:

1. In the purpose section of the SAR, item 1, we don't understand the substitution of BPS by «electric transmission system»; it seems like there is a will to make the Standards applicable to more than the BPS. It is our understanding that NERC Standards are aimed at the reliability of the BPS. The term BPS should be retained and instead of modifying the SAR to widen the applicability, the Standard itself should be modified to specifically used the term BPS in item A.3.
2. In the detailed description section, item 1, sub-bullett , it is written that :``...the SDT may consider other criteria in determining applicability of the Standard to sub 200 kV lines...``. We think that in item 4.3 (Applicability) of the existing Standard, there is already the possibility of applying the Standard to sub 200 kV lines if determined by RRO. This could be reworded by saying:«...as determined by a methodology to define BPS element»; such as the one used by NPCC.
3. We noticed that most Definitions (e.g. RC, IA, PC, RP, TP, TOp, DP, GO, GOp, PSE, MO (not even in the Glossary), LSE) used to described the Reliability Functions in the SAR form, are somewhat different than those used in the Glossary of Terms approved with the Standards deposited at the FERC. For consistency, if the definition needs to be changed, this should be done through the right process, not just casually in the SAR Form.
4. Also, although the title in that same section of the SAR form refers to Reliability Functions, these are in fact the Responsible Entity that performs those functions; maybe a correction in the SAR form would be necessary.

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
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NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*
George Juhn	**Hydro One Networks Inc.**	**NPCC**	1

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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The FERC has urged further industry consideration of a number of issues and these have been listed in the revised SAR as items to address during using standards development process to refine FAC-003-1. The SAR drafting team consensus is that a modification to FAC-003-1 to address the aforementioned items is warranted.

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The SAR drafting team consensus is that modification of FAC-003-1 to address the aforementioned items is needed to ensure reliability of the bulk power system.

1. Do you agree there is a reliability need for the proposed modifications and review of the standard?

☐ Yes

☒ No

Comments: It is our belief that the Standard in its current form does provide adequate provisions and drivers to minimize vegetation related outages and eliminate the likelihood of reoccurence of the August 14, 2003 blackout. However, it is recognized that the industry needs to consolidate its view on these provisions and we support the preparation of a "white paper" that will document the rationale concerning the requirements of the standard, as well as review certain aspects of the standard that have come into question.

2. If you are a transmission owner, have you been provided a list from a Reliability Entity (formerly RRO) of sub 200kV critical transmission lines that must comply with FAC-003-1?

☐ Yes

☒ No

Comments:

3. If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.

☒ Yes

☐ No

Comments: Hydro One clearance standards are based on the Ontario Health and Safety Act (OHSA) clearances rather than the absolute minimum specified in Clearance 2. OHSA clearances at time of work minimize costs for line clearing and brush control. By maintaining OHSA clearances during normal working conditions, staff qualifications required to work near energized facilities are less than under the absolute minimum as stipulated in IEEE 515-3003, and in most cases, the work is less labour and equipment intensive. As part of work planning, qualified staff determine the amount of vegetation that has to be removed to achieve OHSA clearances at the time of the next scheduled work. As well, provisions are built into the clearances at time of work to account for conductor and tree movement during adverse weather conditions. The objective is to provide OHSA clearances under adverse conditions, but these are not always achieved, however clearances are never less than the absolute minimum stipulated in FAC-003-1.

The above provides a description of our planning process. If the Standard Drafting Team would like a copy of the Hydro One standard, this can be provided.

4. Are there any other comments regarding the standard, its possible modifications or the SAR?

☒ Yes

☐ No

Comments: We believe from a transmission system perspective, category 3 outages are no different than many of the other types of outages that take place on the system, such as hardware failures, lightning damage and station equipment outages to name a few. It is our understanding that there is no requirement to report these “other” outages which makes one wonder why the tree related outages that originate off the right of way need to be reported. We are not diminishing the importance of category 3 outages, but from a system cascading perspective, these outages are no more important than other line or station outages, and are fewer in number than the “other” random outages. To initiate system cascading as occurred during August 14, 2003, a number of the random outages would have to coincide to cause a wide spread system event, which in our opinion is a very low probability occurence. On the other hand, a category 1 outage can occur as a result of any system disturbance should there be deficiencies in clearances to vegetation, as such the importance of category 1 outages is apparent and reporting is appropriate. We support the review concerning the need to report category 3 outages and that the ultimate decision should be based on reporting rules that take into consideration the broader topic of reliability, rather than just vegetation related outages.

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
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Organization: IESO		
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NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
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The SAR drafting team consensus is that modification of FAC-003-1 to address the

1. **Do you agree there is a reliability need for the proposed modifications and review of the standard?**

   ☒ Yes

   ☐ No

   Comments:

2. **If you are a transmission owner, have you been provided a list from a Reliability Entity (formerly RRO) of sub 200kV critical transmission lines that must comply with FAC-003-1?**

   ☐ Yes

   ☐ No

   Comments:

3. **If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.**

   ☐ Yes

   ☐ No

   Comments:

4. **Are there any other comments regarding the standard, its possible modifications or the SAR?**

   ☒ Yes

   ☐ No

   Comments:

   1. The SAR indicates that a list of critical low voltage transmission lines will be provided to FERC. We do not interpret Order 693 to direct NERC to provide this list. Rather, we interpret that FERC asks for defining a criteria that would include low voltage transmission lines that have impact on Bulk Power System reliability. We do not think the list is required.

   2. The SAR indicates: “The standard DT may consider other criteria in determining applicability of the standard to sub 200kV lines…” Per Order 693, the criteria is quite clearly stated to be the transmission lines of less than 200 kV that could impact Bulk Power System reliability. We don't feel any other criteria would be necessary. Further, to identify the candidates that meet these criteria, we believe they should be determined by the Reliability Coordinator, similar to the PRC-023 standard, since the RC has the primary responsibility and knowledge of interconnection reliability impact.

   3. We do not understand why the SDT considers removing Category 3 incidents? In our view, Category 3 outages are important information for assessing the effectiveness of vegetation program. Since the industry started reporting vegetation related outages about 3 years ago, data collected so far indicates that of a total of 98 reported vegetation outages, 67 of them were category 3 outages. With this high percentage,

reporting of Category 3 events should be a must since the associated trends can provide valuable information to the TOs to aid its evaluation of the vegetation management program.

4. The white paper and field tests are a good idea and the SDT should be commended for these, especially the white paper.

5. Item 2 under the FERC Order 693 Items in the Detailed Description Section indicates the SDT will also collection outage data. While we understand that FERC has directed the ERO to collect outage data for transmission outages of lines that cross both federal and non-federal lands, we do not feel that it is the SDT's role to perform this task. We feel that this task should be performed by the ERO line functions or a group separate from the SDT such that the task does not add burden to the SDT which may slow down the standard development process or result in the standard development being driven by unanalyzed data and resulting in erroneous requirements.

6. With respect to reporting exemptions, our position during development of the previous version of this standard was to limit them. We commend the SDT intention to clarify the outage exemptions under major disasters, but to consider including all category outage exemptions in the standard body is too prescriptive and will add to the already extended list. It can end up with a very long list of outage exemptions, thereby reducing the coverage of the standard substantially and defeating its purpose.

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Group Comments (Complete this page if comments are from a group.)

Group Name: IRC Standards Review Committee

Lead Contact: Charles Yeung

Contact Organization: SPP

Contact Segment: 2

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Contact E-mail: cyeung@spp.org

Additional Member Name	Additional Member Organization	Region*	Segment*
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Alicia Daugherty	PJM	RFC	2
Ron Falsetti	IESO	NPCC	2
Matt Goldberg	ISO-NE	NPCC	2
Brent Kingsford	CAISO	WECC	2
Steve Myers	ERCOT	ERCT	2
Anita Lee	AESO	WECC	2
Bill Phillips	MISO	RFC+	2
		MRO+	
		SERC	

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1. **Do you agree there is a reliability need for the proposed modifications and review of the standard?**

☒ Yes

☐ No

Comments:

2. **If you are a transmission owner, have you been provided a list from a Reliability Entity (formerly RRO) of sub 200kV critical transmission lines that must comply with FAC-003-1?**

☐ Yes

☐ No

Comments: N/A

3. **If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.**

☐ Yes

☐ No

Comments: N/A

4. **Are there any other comments regarding the standard, its possible modifications or the SAR?**

☒ Yes

☐ No

Comments:

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4. The white paper and field tests are a good idea and the SDT should be commended for these, especially the white paper.

5. Item 2 under the FERC Order 693 Items in the Detailed Description Section indicates the SDT will also collect outage data. While we understand that FERC has directed the ERO to collect outage data for transmission outages of lines that cross both federal and non-federal lands, we do not feel that it is the SDT's role to perform this task. We feel that this task should be performed by the ERO or a group separate from the SDT such that the task does not add burden to the SDT which may slow down the standard development process or result in the standard development being driven by unanalyzed data and resulting in erroneous requirements.

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
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Organization:	ISO New England	
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E-mail:	kgoodman@iso-ne.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
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Contact Organization:

Contact Segment:

Contact Telephone:

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Additional Member Name	Additional Member Organization	Region*	Segment*
		NPCC	

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   ☐ No

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Robert Coish	
Organization:	Manitoba Hydro	
Telephone:	1-204-487-5479	
E-mail:	rgcoish@hydro.mb.ca	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
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   ☒ Yes

   ☐ No

   Comments: The definition of ROW should be clarified. The definition of a critical line should not be kept to a particular voltage threshold. However, consideration could also then be given to exempting non-critical lines operating at higher voltage levels(>200kv). Electrical clearances should be consistent whether on Federal or non-Federal land.

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   ☐ Yes

   ☒ No

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   ☒ Yes

   ☐ No

   Comments: Clearance 1 was developed based on the limits of approach for non-qualified people (public). At a minimum, we would clear beyond this distance during vegetation control activities. Our cycle times and management approach are adjusted for this distance, taking into account growth rates. The values will vary depending on voltage class. Clearance 2 is based on internal design standards that take into account our understanding of switching surge values for our system. The values used are more conservative than IEEE 516-2003.

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   ☐ Yes

   ☒ No

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Thomas E. Sullivan	
Organization:	National Grid	
Telephone:	508-389-9086	
E-mail:	thomas.sullivan@us.ngrid.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
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1. **Do you agree there is a reliability need for the proposed modifications and review of the standard?**

☐ Yes

☒ No

Comments: National Grid believes that compliance with all elements of the present Standard will result in TO's achieving the reliability objectives set forth in the Standard.

2. **If you are a transmission owner, have you been provided a list from a Reliability Entity (formerly RRO) of sub 200kV critical transmission lines that must comply with FAC-003-1?**

☐ Yes

☒ No

Comments: The Reliability Entity has not provided a list of sub 200 kV lines subject to compliance with FAC-003-1. The Standard became effective in February 2007, just 3 months ago. Having no list today should not imply that the RE or the Standard has failed in any way. National Grid suggests that a revised Standard should direct the RE to produce a list of "sub 200 kV critical transmission lines" within 6 to 12 months of adoption.

3. **If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.**

☐ Yes

☒ No

Comments: Detailed methodology is not attached. In summary, National Grid used Table 5 IEEE Section 516 for determing clearance 2. These data for each voltage class were rounded to the next higher whole number. Clearance 1 was determined by adding the clearance 2 distance, conductor sag distance, and anticipated tree growth over the maintenance cycle.

4. **Are there any other comments regarding the standard, its possible modifications or the SAR?**

☒ Yes

☐ No

Comments:
1) National Grid supports amending FAC-003-1 to bring the Standard into compliance with "latest version of the Reliability Standard Development Procedure and the ERO Sanctions Guidelines" as discussed in the SAR Background Information.
2) We do not support amendments to the Standard to address all of the issues raised by FERC Order 693. We believe most of the FERC's concerns can be addressed by developing a "white paper" to better explain the Standard and guide its implementation.
3) National Grid does not support changing the basic approach to defining clearance from vegetation. The clearance 1 and clearance 2 concept adopts the two management approaches used by most TO's today and required in some state or ISO level

standards. National Grid supports using the reference to IEEE 516 as the basis for clearance 2 for two reasons: 1 - there is no other definitive reference for flash over distances to vegetation and 2- decades of experience by TO's acrosss the North America suggest the IEEE 516 distances are more than adequate. The well known tree caused outages in 1996 and 2003 occurred as a result of hard contact with vegetation not flashover at distances close to those in IEEE 516. Furthermore, FERC accepted IEEE 516 as appropriate for use in vegetation management in the October 2006, NOPR.
4) National Grid supports amending the definition of a right-of-way though we are not clear on what is meant in the SAR language by "to encompass required clearing areas". National Grid is concerned with the interpretation of the present definition that the right-of-way includes uncleared fee owned or easement land reserved for future construction. In many jurisdictions the TO may not be allowed to remove trees from these areas. A "white paper" could better describe the definition and prevent future compliance issues stemming from an ambiguous definition.

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Name: Michael Calimano		
Organization: New York Indepentant System Operator		
Telephone: 518-356-6129		
E-mail: mcalimano@nyiso.com		
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1. The SAR indicates that a list of critical low voltage transmission lines will be provided to FERC. We do not interpret Order 693 to direct NERC to provide this list. Rather, we interpret that FERC asks for defining a criteria that would include low voltage transmission lines that have impact on Bulk Power System reliaiblity. We do not think the list is required.

2. The SAR indicates: “The standard DT may consider other criteria in determining applicability of the standard to sub 200kV lines…” Per Order 693, the criteria is quite clearly stated to be the transmission lines of less than 200 kV that could impact Bulk Power System reliability. We don't feel any other criteria would be necessary. Further, to identify the candidates that meet this criteria, we believe they should be determined by the Reliability Coordinator, similar to the PRC-023 standard, since the RC has the primary responsibility and knowledge of interconnection reliability impact.

3. We do not understand why the SDT considers removing Category 3 incidents? In our view, Category 3 outages are important information for assessing the effectiveness of vegetation program. Since the industry started reporting vegetation related outages about 3 years ago, data collected so far indicates that of a total of 98 reported vegetation outages, 67 of them were category 3 outages. With this high percentage,

reporting of Category 3 events should be a must since the associated trends can provide valuable information to the TOs to aid its evaluation of the vegetation management program.

4. The white paper and field tests are a good idea and the SDT should be commended for these, especially the white paper.

5. Item 2 under the FERC Order 693 Items in the Detailed Description Section indicates the SDT will also collect outage data. While we understand that FERC has directed the ERO to collect outage data for transmission outages of lines that cross both federal and non-federal lands, we do not feel that it is the SDT's role to perform this task. We feel that this task should be performed by the ERO or a group separate from the SDT such that the task does not add burden to the SDT which may slow down the standard development process or result in the standard development being driven by unanalyzed data and resulting in erroneous requirements.

6. With respect to reporting exemptions, our position during development of the previous version of this standard was to limit them. We commend the SDT intention to clarify the outage exemptions under major disasters, but to consider including all category outage exemptions in the standard body is too prescriptive and will add to the already extended list. It can end up with a very long list of outage exemptions, thereby reducing the coverage of the standard substatively and defeating its purpose. If this list was to be developed, they could be attached as guidelines aside of the standard.

Please use this form to submit comments on the draft Transmission Vegetation Management SAR. Comments must be submitted by **May 9, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words **"Vegetation Management SAR"** in the subject line. If you have questions please contact Harry Tom at Harry.Tom@nerc.net or by telephone at 609-452-8060.

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name: Anthony Johnson		
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NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information:

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The SAR drafting team modified the SAR to state more specifically that the revisions to the standard need to incorporate the compliance program elements of time horizons and violation severity levels to bring FAC-003-1 into conformance with the latest version of the Reliability Standard Development Procedure and the ERO Sanctions Guidelines.

The FERC has urged further industry consideration of a number of issues and these have been listed in the revised SAR as items to address during using standards development process to refine FAC-003-1. The SAR drafting team consensus is that a modification to FAC-003-1 to address the aforementioned items is warranted.

Please review the changes made to the Vegetation Management SAR and then respond to the questions on the following pages. Please e-mail your comments to sarcomm@nerc.net with the subject "Vegetation Management SAR" by **May 9, 2007.**

You need not answer all questions. Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

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The SAR drafting team also modified the SAR to clarify that the scope of revisions to this standard will include addressing the issues raised by FERC in Order 693, including the following:

- Consideration of minimum clearances needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal land and non-federal land
- Revisions to the definition of 'right of way' to encompass required clearance areas
- Review of the suitability of IEEE Standard 516-2003 for minimum vegetation clearance

Several commenters indicated that the reporting requirements may need revision and the SAR was revised to include consideration of modifications to the reporting requirements.

The SAR drafting team consensus is that modification of FAC-003-1 to address the aforementioned items is needed to ensure reliability of the bulk power system.

1. **Do you agree there is a reliability need for the proposed modifications and review of the standard?**

☐ Yes

☒ No

Comments: Proposed modifications do not increase the levels of reliability above what is already required in the current version of the Stnadard.

2. **If you are a transmission owner, have you been provided a list from a Reliability Entity (formerly RRO) of sub 200kV critical transmission lines that must comply with FAC-003-1?**

☐ Yes

☒ No

Comments: The Reliability Entity has not provided a list of facilities covered under FAC-003-1. This is not a fault of the RE as there has been no direction provided as to what factors or charateristics are required for sub-200kV lines to be included under the Standard. It is our position that the factors that will be used to develop the list of sub-200kV faciltities to be covered by the Standard be developed at the national level (NERC) and adopted by all RE's for consistency.

3. **If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.**

☒ Yes

☐ No

Comments: The methodology for determining clearance 2 is based on the requirements of FAC-003-1. The IEEE Section 516 has been considered the base minimum limits for clearances as provided under FAC-003-1 R.1.2.2. Clearances used for R.1.2.1 on the NU Transmission System comply with the requirements of ISO-NE Operating Procedure OP-3, that provides clearance levels required at the time of vegetation trimming or clearing under the various transmission voltages.

4. **Are there any other comments regarding the standard, its possible modifications or the SAR?**

☒ Yes

☐ No

Comments: NU does not support the proposed revisions based on the issues raised by FERC Order 693. The Standard has not been in effect long enough to determine if there are any shortcomings with the current requirements. It is our position that the current clearance requirements are satisfactory in that a base minimum distance as provided under IEEE Section 516 is sufficient and there is the need for variations in the second level of clearances base on Regional needs and conditions.

The revisions to the definition of "right-of-way" to encompass required clearance areas canbe problematic as this could cause significant problems with current systems. There is no detailed description on what the new defition will include or what the actual impact will be to TO's. If the definition will include defined limits or widths of rights-of-way this may affect current facilities that do not meet these distances. Second, there are areas where the company owns or possesses additional area beyond the current maintained right-of-way widths. Is it proposed that the new definition expand the limits of clearing or maintenance to include easemented or fee-owned areas beyond the current maintained limits? Until the new definition can be presented - it is difficult to support any changes at this time and we can only comment on the percevied negative impacts.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
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Group Comments (Complete this page if comments are from a group.)

Group Name: 1

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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The FERC has urged further industry consideration of a number of issues and these have been listed in the revised SAR as items to address during using standards development process to refine FAC-003-1. The SAR drafting team consensus is that a modification to FAC-003-1 to address the aforementioned items is warranted.

Please review the changes made to the Vegetation Management SAR and then respond to the questions on the following pages. Please e-mail your comments to sarcomm@nerc.net with the subject "Vegetation Management SAR" by **May 9, 2007.**

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- Review of the suitability of IEEE Standard 516-2003 for minimum vegetation clearance

Several commenters indicated that the reporting requirements may need revision and the SAR was revised to include consideration of modifications to the reporting requirements.

The SAR drafting team consensus is that modification of FAC-003-1 to address the aforementioned items is needed to ensure reliability of the bulk power system.

1. **Do you agree there is a reliability need for the proposed modifications and review of the standard?**

   ☒ Yes

   ☐ No

   Comments: As stated in the SAR

2. **If you are a transmission owner, have you been provided a list from a Reliability Entity (formerly RRO) of sub 200kV critical transmission lines that must comply with FAC-003-1?**

   ☒ Yes

   ☐ No

   Comments: Provided from WECC

3. **If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.**

   ☒ Yes

   ☐ No

   Comments: Will be provided to the SARDT in a separate attachment

4. **Are there any other comments regarding the standard, its possible modifications or the SAR?**

   ☒ Yes

   ☐ No

   Comments:
   1) Applicability 4.3 of the standard - PG&E believes the RE is in the best position to determine sub-200kV facilities are designated critical and covered under FAC-003-1. We suggest the ERO direct the RE to provide a list of sub-200kV lines designated critical along with methodology used to make that determination.

   2) Clearances for lines on federal and non-federal lands - PG&E believes there should be no distinction between requirements on different lands. Vegetation encroachments have the same impact regardless of land ownership.

   3) Definition of right of way - agreed

   4) Suitability of IEEE 516-2003 - PG&E believes the use of IEEE 516 as the standard for clearance requirements are adequate to ensure transmission system reliability provided the TO has an appropriate methodology for determining clearance at time of trim and an adequate cycle to prevent vegetation from encroaching within minimum distances. Use of ANSI Z133.3 or FedOSHA 1910, as suggested by FERC, is not appropriate as it is intended for worker safety and not system reliability. TO compliance with R1.2 of the standard should address concerns FERC has with maintaining minimum clearance.

   5-7) Procedural items - No comment

8) Preparation of technical manual (white paper) - agreed

9) PG&E believes the current reporting requirements under R3 of the standard should be revised. Distinction is placed on fall-in's "in and out of the ROW" and may not be the best method for determining severity for reporting purposes. PG&E believes a better distinction is (a) green/healthy/no obvious decline and (b) dead or obvious signs of disease, decay or decline. A key component of any TMVP should be hazard tree mitigation regardless if in or out of the ROW. Suggested categories:

Category 1 - Any grow-in (as currently stated).
Category 2 - Any fall-in of a dead tree or one with obvious signs of disease, decay or decline in or out of the ROW.
Category 3 - Either eliminate this category or specify healthy green tree or tree with no obvious signs of decline (if retained, be specific about this being for reporting purposes only)

PG&E recognizes that tree failures, even if dead or diseased, are not necessarily an indicator of problematic VM program and the severity level should be reflected as such. Tree density along with other factors make 100% identification not possible. However, multiple occurrences could be an indicator of substandard performance and the current standard does remains silent in respect to hazard trees other than if in or out of the ROW.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☒ **FRCC**	☐	2 — RTOs and ISOs
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- Review of the suitability of IEEE Standard 516-2003 for minimum vegetation clearance

Several commenters indicated that the reporting requirements may need revision and the SAR was revised to include consideration of modifications to the reporting requirements.

The SAR drafting team consensus is that modification of FAC-003-1 to address the aforementioned items is needed to ensure reliability of the bulk power system.

1. Do you agree there is a reliability need for the proposed modifications and review of the standard?

☐ Yes

☒ No

Comments: Progress Energy Carolinas and Progress Energy Florida are providing an answer to the question as it relates to the reliability need. The current standard contains appropriate requirements and measures to ensure the Transmission Owner's vegetation management program is implemented and managed to ensure the reliability of the transmission system. In addition, we do not believe that a standard with a zero tolerance for vegetation-related outages in the ROW is in need of reliability-based revisions.

However, we do recognize the need for a revision of the standard to address non-reliability related items that are in the SAR. Procedural items such as formatting and clarifications, such as the definition of right-of-way, need to be, and should be, addressed.

2. If you are a transmission owner, have you been provided a list from a Reliability Entity (formerly RRO) of sub 200kV critical transmission lines that must comply with FAC-003-1?

☐ Yes

☒ No

Comments: The SERC and FRCC regions have not identified any lines below 200kV to be critical to the electrical system in the region. Since no lines have been identified as critical to the region, no list has been provided to Progress Energy Carolinas and Progress Energy Florida. (please note our comments on this issue in question #4)

3. If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.

☒ Yes

☐ No

Comments: Progress Energy has an individual on the Drafting Team and will share the Progress Energy Florida clearance Tables with the team.

4. Are there any other comments regarding the standard, its possible modifications or the SAR?

☒ Yes

☐ No

Comments: Progress Energy Carolinas (PEC) and Progress Energy Florida (PEF) do not agree that each of 11 items listed in the SAR are necessary to improve reliability. The following comments are offered for each of the 11 items identified in the SAR detail description:

1. Standard Applicability:

PEC and PEF believe that the current standard wording for determining facilities subject to this standard should not be revised. The standard as it is written provides for lines below 200kV, that are determined to impact the grid, to be subject to the standard.

Extending the requirements to a bright line below 200kV, such as 100kV, will dilute the focus on those lines that impact grid reliability, lines >200kV, and shift attention to facilities, those <200kV, that do not necessarily impact grid reliability. Customer reliability is an issue that impacts customer satisfaction and is generally driven by state utility commissions. While some facilities above 200kV directly support customer load, transmission lines below 200kV primarily support customer load, and interruptions to those facilities generally reduce load on the grid.

The majority of transmission facilities below 200 kV also have significantly different design/construction/operating characteristics and have not been cited as impacting bulk power system reliability. For example, the Final Report on the August 14, 2003 Blackout in the United states and Canada: Causes and Recommendations April 2004 by the U.S.- Canada Power System Outage Task Force and all referenced major blackouts (pages 103-115) in that report, cited only outages which involved vegetation at line voltages above 200kV. Generally applying requirements that are appropriate for >200kV lines to lines less than 200kV will result in significant documentation and reporting of items such as restrictions, mitigation plans, off right-of-way vegetation-related outage investigation/ information and other issues, all of which dilutes the focus on lines that directly impact bulk power system reliability.

Revising the standard to use general criteria or broad language for defining "Bulk Power System" transmission lines covered by the standard is a “one size fits all” approach. If that approach were taken, the standard would cover a significant number of transmission lines that have no direct impact on bulk power system reliability under standard planning/operating conditions, resulting in a significant cost burden for electric customers without improving “grid” reliability. PEC and PEF believe that the applicability provision of the standard should instead focus attention of the standard only on the transmission lines below 200kV that directly impact “Bulk Power System” reliability, as the current version requires.

While PEC and PEF recognize some validity in the Commission’s concern, PEC and PEF recommend that the applicability provision of this standard should be revised only if existing system design, planning or operating reliability criteria and parameters are considered as a basis for defining the applicability of the standard. To that end, PEC and PEF recommend each Regional Entity (RE) determine applicability of FAC-003 to those lines within the region that are between 100kV and 200KV, if, and only if, they are identified as operationally significant elements of Interconnection Reliability Operating Limits (“IROLs”). That is, any facility below 200kV that, by itself, would cause an Interconnected Reliability Limit Violation should the facility be outaged.

2. Issue of Clearances (Federal vs Non-Federal Lands):

FAC-003-1 presently requires the transmission owner (TO) “identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway.” The intent of this requirement is to ensure adequate clearances to prevent vegetation related outages. PEC and PEF believe that only the TO has the technical information required to determine the clearances that are necessary at the time of VM work and that any "federal lands exemption" to clearances will result in inadequate clearances for the existing conditions. Consistency in application of the TO's clearance requirements, not exceptions, is the only assurance in providing a uniform and reliable electrical system to meet the nation's current and future energy demands.

Any exception for a case by case clearance approach to determine vegetation management activities/clearances on Federal lands will continue to drive inconsistency and/or delays associated with TO vegetation management decisions being driven by diverse vegetation management practices/beliefs and staff changes at the local level of Federal agencies. Vegetation-related outages have occurred on Federal lands as a result of this case by case approach, and if "Bulk Power Transmission System" lines continue to be addressed on a "case by case" basis on National Forest Service (or any other Federal lands), those lines will potentially be subject to a higher risk for vegetation-related outages, resulting in reduced reliability for the "Bulk Power System".

PEC and PEF believe that reliability of the "Bulk Power System" should have the same focus on Federal and private lands and that the EEI MOU with federal agencies is an appropriate avenue for TO's to identify clearances on Federal lands, not an exemption in the language of a reliability standard.

3. Defining Right-of-Way:

PEC and PEF agree that it is appropriate to further address the definition of "right-of-way". Corridor widths that exceed the design clearance requirements have been acquired for a variety of reasons in the past; future use, property line buffers, etc. Vegetation in those areas that would normally be outside of the corridor width necessary for reliable operation of the facility, but within an expanded easement area, should not be considered, or treated, different than vegetation that is outside of a defined easement/permit right-of-way corridor that was designed and acquired specifically for the reliable operation of a single line.

4. IEEE Standard for Minimum Clearances:

PEC and PEF believe that the IEEE 516-2003 tables are appropriate for defining the minimum acceptable clearances to prevent flashover between conductors and vegetation under all rated electrical operating conditions. Closer minimum clearances such as the minimum length of a support insulator could have been adopted as a "lowest common denominator" clearance. However the clearance in IEEE 516-2003 was adopted to ensure an additional margin of reliability. FERC staff has made references to the use of ANSI Z-133 which is a safety standard that addresses worker safety as well as the safety of the general public. The purpose of ANSI Z-133 is to address worker safety and is not focused on transmission line reliability, which is the purpose of FAC-003-1. OSHA, NESC and other related safety standards have clearances in excess of IEEE 516-2003. Those clearances are clearly focused on safety issues and will still apply to other aspects of design and operation of electric facilities (such as public and worker safety) but are not appropriate to be referenced in a vegetation management reliability standard as a flashover clearance.

5/6/7. Procedural Items:

PEC and PEF agree that the procedural items related to formatting RRO references and revising the compliance elements to meet the new standard format should be addressed by the standard drafting team.

8. Technical Reference Materials:

PEC and PEF agree that a “white paper” that defines the technical basis for the standard is appropriate. This type of document, if crafted by the drafting team, should help to avoid the potential for differences in interpretation of the standard’s requirements by the various regions during the audit process.

9. Category 3 Outages:

Since control off right-of-way vegetation is generally beyond control of the TO and since "fall-in" outages are random events that do not threaten grid reliability, PEC and PEF believe that the reporting of category 3 outages should be removed from the requirements.

10. Requirement R4:

PEC and PEF believe that requirement R4 should be deleted from the standard, since the ERO formation provides for delegation of authority to the regional entities.

11. Reporting Exemptions:

PEC and PEF believe that the reporting requirement exemptions for natural disasters should include all categories of outages. For example, with outages caused by high winds, hurricanes, tornadoes, etc., it would be difficult (or practically impossible in some cases) to determine if the vegetation came from on, or off, the "right-of-way". In addition, the effort and time necessary to make that determination would result in delaying outage restoration efforts.

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Group Comments (Complete this page if comments are from a group.)

Group Name: Public Service Commission of South Carolina

Lead Contact: **Philip Riley**

Contact Organization: **Public Service Commission of South Carolina**

Contact Segment: **9**

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Additional Member Name	Additional Member Organization	Region*	Segment*
Mignon L. Clyburn	**Public Service Commission of SC**	**SERC**	9
Elizabeth B. "Lib" Fleming	**Public Service Commission of SC**	**SERC**	9
G. O'Neal Hamilton	**Public Service Commission of SC**	**SERC**	9
John E. "Butch" Howard	**Public Service Commission of SC**	**SERC**	9
Randy Mitchell	**Public Service Commission of SC**	**SERC**	9
C. Robert "Bob" Moseley	**Public Service Commission of SC**	**SERC**	9
David A. Wright	**Public Service Commission of SC**	**SERC**	9

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The SAR drafting team consensus is that modification of FAC-003-1 to address the aforementioned items is needed to ensure reliability of the bulk power system.

1. **Do you agree there is a reliability need for the proposed modifications and review of the standard?**

   ☒ Yes

   ☐ No

   Comments:

2. **If you are a transmission owner, have you been provided a list from a Reliability Entity (formerly RRO) of sub 200kV critical transmission lines that must comply with FAC-003-1?**

   ☐ Yes

   ☐ No

   Comments:

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   ☐ Yes

   ☐ No

   Comments:

4. **Are there any other comments regarding the standard, its possible modifications or the SAR?**

   ☐ Yes

   ☒ No

   Comments:

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</table>

Group Comments (Complete this page if comments are from a group.)

Group Name: SERC Vegetation Management Subcommittee

Lead Contact: **Richard Dearman**

Contact Organization: **SERC Engineering Committee, Vegetation Management Subcommittee**

Contact Segment: **1**

Contact Telephone: **(256) 519-2067**

Contact E-mail: **redearman@tva.gov**

Additional Member Name	Additional Member Organization	Region*	Segment*
Jay Farrington	**Alabama Electric Cooperative, I.**	**SERC**	1
Randy Gann	**Alabama Power Co.**	**SERC**	1
Raymond Wiesehan	**Ameren**	**SERC**	1
John Neagle	**Associated Electric Coop**	**SERC**	1
Billy George	**Duke Energy, Carolinas**	**SERC**	1
Ralph Hale	**Entergy**	**SERC**	1
Marc Tunstall	**Fayetteville Public Works Comm**	**SERC**	1
Jack Gardner	**Progress Energy Carolinas**	**SERC**	1
Jerry Lindler	**South Carolina Electric & Gas**	**SERC**	1
John Wolfmeyer	**SERC Reliability Corporation**	**SERC**	10

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1. Do you agree there is a reliability need for the proposed modifications and review of the standard?

☐ Yes

☒ No

Comments: The SERC VMS is providing an answer to the question as it relates to the reliability need. The current standard contains appropriate requirements and measures to ensure the Transmission Owner's vegetation management program is implemented and managed to ensure the reliability of the transmission system. In addition, we do not believe that a standard with a zero tolerance for vegetation-related outages in the ROW is in need of reliability-based revisions.

However the SERC VMS recognizes the need for a revision of the standard to address non-reliability related items that are in the SAR. Procedural items such as formatting and clarifications, such as the definition of right-of-way, need to be, and should be, addressed.

2. If you are a transmission owner, have you been provided a list from a Reliability Entity (formerly RRO) of sub 200kV critical transmission lines that must comply with FAC-003-1?

☐ Yes

☒ No

Comments: The SERC region has not identified any lines below 200kV to be critical to the electrical system in the region. Since no lines have been identified as critical to the region, no list has been provided to Transmission Owners. (please note the subcommittee's comments on this issue in question #4)

3. If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.

☐ Yes

☐ No

Comments: This question does not apply to the SERC EC Vegetation Mangement Subcommittee.

4. Are there any other comments regarding the standard, its possible modifications or the SAR?

☐ Yes

☐ No

Comments: The SERC VMS does not agree that each of 11 items listed in the SAR are necessary to improve reliability. The following comments are offered for each of the 11 items identified in the SAR detail description:

1. Standard Applicability:

The SERC VMS disagrees with revising the 200 kV threshold for determining facilities subject to this standard. Extending the requirements to lines other than those >200kV will dilute the focus on those lines that impact grid reliability and shift attention to facilities, those <200kV. The reliability of lower voltage lines involves local customers' reliability and satisfaction hence that reliability should be addressed by local and state utility commissions. The majority of the >200kV lines are solely elements of the grid and and interruptions to those lines negatively impact grid reliability. The majority of the <200kV lines primarily support customer load, and interruptions to those facilities actually reduces load on the grid.

The majority of transmission facilities below 200 kV also have significantly different design/construction/operating characteristics and have not been cited as impacting bulk power system reliability. For example, the Final Report on the August 14, 2003 Blackout in the United states and Canada: Causes and Recommendations April 2004 by the U.S.- Canada Power System Outage Task Force and all referenced major blackouts (pages 103-115) in that report, cited only outages which involved vegetation at line voltages above 200kV. Generally applying requirements that are appropriate for >200kV lines to lines less than 200kV will result in significant documentation and reporting of items such as restrictions, mitigation plans, off right-of-way vegetation-related outage investigation/ information and other issues, all of which dilutes the focus on lines that directly impact bulk power system reliability.

Revising the standard to use general criteria or broad language for defining "Bulk Power System" transmission lines covered by the standard is a “one size fits all” approach. If that approach were taken, the standard would cover a significant number of transmission lines that have no direct impact on bulk power system reliability under standard planning/operating conditions, resulting in a significant cost burden for electric customers without improving “grid” reliability. The SERC VMS believes that the applicability provision of the standard should instead focus attention of the standard only on the transmission lines below 200kV that directly impact “Bulk Power System” reliability, as the current version requires.

In sum, while the SERC VMS recognizes some validity in the Commission’s concern, the SERC VMS recommends that the applicability provision of this standard should be revised only if existing system design, planning or operating reliability criteria and parameters are considered as a basis for defining the applicability of the standard. To that end, the SERC VMS recommends each Regional Entity (RE) determine applicability of FAC-003 to those lines within the region that are between 100kV and 200KV, if, and only if, they are identified as operationally significant elements of Interconnection Reliability Operating Limits (“IROLs”). That is, any facility below 200kV that by itself would cause an Interconnected Reliability Limit Violation should the facility be outaged.

2. Issue of Clearances (Federal vs Non-Federal Lands):

FAC-003-1 presently requires the transmission owner (TO) “identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway.” The intent of this requirement is to ensure adequate clearances to prevent vegetation related outages. The SERC VMS believes that only the TO has the technical information required to determine the clearances that are necessary at the time of VM work and that any “federal lands exemption” to clearances will result in

inadequate clearances for the existing conditions. Consistency in application of the TO's clearance requirements, not exceptions, is the only assurance in providing a uniform and reliable electrical system to meet the nation's current and future energy demands.
Any exception for a case by case clearance approach to determine vegetation management activities/clearances on Federal lands will continue to drive inconsistency and/or delays associated with TO vegetation management decisions being driven by diverse vegetation management practices/beliefs and staff changes at the local level of Federal agencies. Vegetation-related outages have occurred on Federal lands as a result of this case by case approach, and if "Bulk Power Transmission System" lines continue to be addressed on a "case by case" basis on National Forest Service (or any other Federal lands), those lines will potentially be subject to a higher risk for vegetation-related outages, resulting in reduced reliability for the "Bulk Power System".

The SERC VMS believes that reliability of the "Bulk Power System" should have the same focus on Federal and private lands and that the EEI MOU with federal agencies is the appropriate vehicle for TO's to identify clearance variances on Ferderal lands, not exemption language in the standard.

3. Defining Right-of-Way:

The SERC VMS agrees that it is appropriate to further address the definition of "right-of-way". Corridor widths beyond design clearance requirements have been acquired for a variety of reasons in the past; future use, property line buffers, etc. Vegetation in those areas that would normally fall outside of the area necessary for operation of the facility should not be considered or treated different than vegetation that is outside of a defined easement/permit area that is designed for the reliable operation of an existing single line corridor.

4. IEEE Standard for Minimum Clearances:

The SERC VMS disagrees with objections to the use of the IEEE 516-2003 clearance as the minimum acceptable distances for "Clearance 2". The IEEE 516-2003 tables are appropriate for defining the minimum acceptable clearances to prevent flashover between conductors and vegetation under all rated electrical operating conditions. Closer minimum clearances such as the minimum length of a support insulator could have been adopted as a "lowest common denominator" clearance. However the clearance in IEEE 516-2003 was adopted to ensure an additional margin of reliability. FERC staff references ANSI Z-133 which is a safety standard that addresses worker safety as well as the safety of the general public. As such, the purpose of ANSI Z-133 is to address worker safety and is not focused on transmission line reliability, which is the purpose of FAC-003-1. OSHA, NESC and other related safety standards have clearances in excess of IEEE 516-2003. Those clearances are clearly focused on safety issues and will still apply to other aspects of design and operation of electric facilities (such as public and worker safety) but are not appropriate to be referenced in a vegetation management reliability standard.

5/6/7. Procedural Items:

The SERC VMS agrees that the procedural items related to formatting RRO references and additional compliance elements should be addressed by the standard drafting team.

8. Technical Reference Materials:

The SERC VMS agrees that a “white paper” that defines the technical basis for the standard is appropriate to avoid the potential for differences in interpretation of the standard’s requirements during the various region's audit processes.

9. Category 3 Outages:

Since the right to control off right-of-way vegetation is generally beyond control of the TO, the SERC VMS believes that the reporting of category 3 outages should be removed from the requirements.

10. Requirement R4:

The SERC VMS believes that requirement R4 should be deleted from the standard, based on the ERO formation and the process for delegation of authority to the regional entities.

11. Reporting Exemptions:

The SERC VMS believes that the reporting requirement exemptions for natural disasters should include all categories of outages. It would, for example, be difficult, without delaying restoration efforts, to determine if the vegetation from high winds, hurricanes, tornadoes, etc. is from on or off the "right-of-way".

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Group Comments (Complete this page if comments are from a group.)

Group Name: Southern Company Transmission

Lead Contact: **Roman Carter**

Contact Organization: **Southern Company Transmission**

Contact Segment: **1**

Contact Telephone: **205.257.6027**

Contact E-mail: **jrcarter@southernco.com**

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Steve Burns	**Gulf Power Co.**	**SERC**	1
Randall Gann	**Alabama Power Co.**	**SERC**	1
Steve Craig	**Mississippi Power Co.**	**SERC**	1
Ron Reinike	**Mississippi Power Co.**	**SERC**	1
Ken Trump	**Gulf Power Co.**	**SERC**	1
Nancy Huddleston	**Georgia Power Co.**	**SERC**	1

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1. **Do you agree there is a reliability need for the proposed modifications and review of the standard?**

   ☐ Yes

   ☒ No

   Comments: We do not feel there is a reliability need for modifying the standard. However, we do agree certain modifications are needed to clarify procedural issues such as the amount of time allowed for taking corrective action when items are found to be out of compliance.

2. **If you are a transmission owner, have you been provided a list from a Reliability Entity (formerly RRO) of sub 200kV critical transmission lines that must comply with FAC-003-1?**

   ☒ Yes

   ☒ No

   Comments: We are not really sure how to answer this question. The Regional Entity has not sent us a list, but they have advised us that we do not have any sub 200 kv critical transmisison lines that must comply with FAC-003-1.

3. **If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.**

   ☒ Yes

   ☐ No

   Comments: IEEE 516-2003, Section 4.2.2.3 was adopted as the minimum allowable distance for Clearance 2, with the expectation that work would normally occur prior to Clearance 2 reaching the minimum allowable distance. Clearance 1 was determined by using the Clearance 2 value and adding a growth buffer. Sagging of conductors and their movement in wind was then considered to ensure the growth buffer is adequate.

4. **Are there any other comments regarding the standard, its possible modifications or the SAR?**

   ☐ Yes

   ☒ No

   Comments: We appreciate the efforts of the SAR Drafting Team.

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Name: Richard Dearman		
Organization: TVA		
Telephone: 256-851-3523		
E-mail: redearman@tva.gov		
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1. **Do you agree there is a reliability need for the proposed modifications and review of the standard?**

   ☒ Yes

   ☐ No

   Comments: The primary needs for mocdifications to this standard are in areas to address clarifications and formatting not reliability related issues.

2. **If you are a transmission owner, have you been provided a list from a Reliability Entity (formerly RRO) of sub 200kV critical transmission lines that must comply with FAC-003-1?**

   ☐ Yes

   ☒ No

   Comments: We detemined that there are no TVA lines below 200kv that must comply to this standard due to their criticial needs in SERC.

3. **If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.**

   ☒ Yes

   ☐ No

   Comments: We utilize a clearance 2 based on IEEE 516 2003 Table 5 criteria. Our Clearance 1 is a greater amount to allow for growth between clearing and next inspection or clearance activities. We will provide our tables is requested.

4. **Are there any other comments regarding the standard, its possible modifications or the SAR?**

   ☒ Yes

   ☐ No

   Comments: We feel that the reporting of Category 3 outages should be eliminated. We agree with the need for a "white paper" to expand on definitions and intent. We feel that a defined maintainable width of right of way is more appropriate than the actual easement widths because easement widhts are not purchased or operated exclusively with or for vegetation manitenance activies. We will be pleased to share greater details on this concern if requested.

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name: Jeffrey S. Disorda		
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Telephone: 802-770-6240		
E-mail: jdisorda@velco.com		
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You need not answer all questions. Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

The SAR drafting team considered stakeholder comments on the first draft of this SAR and the FERC Order 693 in preparing the second draft of the SAR to modify FAC-003-1 — Transmission Vegetation Management.

The SAR drafting team modified the SAR to clarify that FAC-003-1 needs to add time horizons and violation severity levels to bring the standard into conformance with the latest version of the Reliability Standards Development Procedure and the ERO Sanctions Guidelines. (Time Horizons and Violation Severity Levels are both elements used to determine an appropriate sanction for violation of a standard.)

The SAR drafting team also modified the SAR to clarify that the scope of revisions to this standard will include addressing the issues raised by FERC in Order 693, including the following:

- Consideration of minimum clearances needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal land and non-federal land
- Revisions to the definition of 'right of way' to encompass required clearance areas
- Review of the suitability of IEEE Standard 516-2003 for minimum vegetation clearance

Several commenters indicated that the reporting requirements may need revision and the SAR was revised to include consideration of modifications to the reporting requirements.

The SAR drafting team consensus is that modification of FAC-003-1 to address the aforementioned items is needed to ensure reliability of the bulk power system.

1. **Do you agree there is a reliability need for the proposed modifications and review of the standard?**

   ☐ Yes

   ☐ No

   Comments:

2. **If you are a transmission owner, have you been provided a list from a Reliability Entity (formerly RRO) of sub 200kV critical transmission lines that must comply with FAC-003-1?**

   ☐ Yes

   ☒ No

   Comments: VELCO has not been provided a specific list of critical lines below 200kV from the RE that need to be in compliance with FAC-003-1. VELCO suggests changing the wording in the standard to indentify those lines affected as 200 kV and great or those defined as Bulk Power System facilities.

3. **If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.**

   ☐ Yes

   ☒ No

   Comments: VELCO has defined Clearance 1 as the maximum allowed vegetation heights (12ft high) at time of maintenance. This maximum height has evolved from experience with regional growth rates and other factors. VELCO's Clearance 2 is determined by the New England ISO's Operating Procedure 3, which is slightly more stringent than IEEE 516.

4. **Are there any other comments regarding the standard, its possible modifications or the SAR?**

   ☐ Yes

   ☒ No

   Comments:

Consideration of Comments on Second Draft of Vegetation Management SAR (Project 2007-07)

The Vegetation Management SAR drafting team thanks all commenters who submitted comments on Draft 2 of the SAR. This SAR was posted for a 30-day public comment period from April 20 through May 9, 2007. The drafting team asked stakeholders to provide feedback on the SAR through a special SAR Comment Form. There were 27 sets of comments, including comments from 65 different people from more than 50 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the drafting team recommends that the Standards Committee advance this SAR to the standard drafting step of the standard development process. The drafting team made only one minor modification to the SAR to clarify (on page 2) that it is the ERO that will collect vegetation-related transmission outage data, not the SDT.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Vegetation-Management_Project_2007-7.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Anita Lee (G1)	AESO		✓								
2.	Jay Farrington (G5)	Alabama Electric Coop.	✓									
3.	Randy Gann (G5) (G6)	Alabama Power	✓									
4.	Ken Goldsmith (G6)	ALT										✓
5.	Mary Hetz	Ameren	✓									
6.	Raymond Wiesehan (G5)	Ameren	✓									
7.	Thad Ness	American Electric Power	✓				✓	✓				
8.	John Neagle (G5)	Associated Electric Coop.	✓									
9.	William T. Rees, Jr.	Baltimore Gas & Electric										
10.	Dave Rudolph (G6)	Basin Electric Power Coop.										✓
11.	Brent Kingsford (G1)	CAISO		✓								
12.	John R. Kellum, Jr.	CenterPoint Energy	✓									
13.	Weston J. Davis	Central Maine Power	✓									
14.	CJ Ingersoll	Constellation (CEDC)			✓							
15.	Gene Walton	Dominion	✓									
16.	Gregory Rowland	Duke Energy	✓		✓		✓	✓				
17.	Billy George (G5)	Duke Energy, Carolinas	✓									
18.	Ralph Hale (G5)	Entergy	✓									
19.	Paul D. Olivier	Entergy Corporation	✓									
20.	Steve Myers (G1)	ERCOT		✓								
21.	Marc Tunstall (G5)	Fayetteville Public Works Comm.	✓									
22.	Doug Hohlbaugh	FirstEnergy Corp.	✓									
23.	John Tamsberg	Florida Power & Light Co.	✓									
24.	Nancy Huddleston (G6)	Georgia Power Co.	✓									
25.	Joe Knight (G6)	Great River Energy										✓
26.	Steve Burns (G6)	Gulf Power Co.	✓									

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
27.	Ken Trump (G6)	Gulf Power Co.	✓									
28.	David Kiguel	Hydro One Networks Inc.	✓									
29.	George Juhn	Hydro One Networks Inc.	✓									
30.	Roger Champagne	Hydro-Québec TransÉnergie (HQT)	✓									
31.	Ron Falsetti (I) (G1)	Independent Electricity SO		✓								
32.	Matt Goldberg (G1)	ISO-NE		✓								
33.	Kathleen Goodman (I) G2)	ISO-NE		✓								
34.	Robert Coish (I) (G6)	Manitoba Hydro	✓		✓		✓	✓				
35.	Terry Bilke (G6)	Midwest ISO										✓
36.	Mike Brytowski (G6)	Midwest Reliability Organization										✓
37.	Carol Gerou (G6)	Minnesota Power										✓
38.	Bill Phillips (G1)	MISO		✓								
39.	Steve Craig (G6)	Mississippi Power Co.	✓									
40.	Ron Reinike (G6)	Mississippi Power Co.	✓									
41.	Thomas E. Sullivan	National Grid	✓									
42.	Anthony Johnson	Northeast Utilities		✓								
43.	Mike Calimano (I) (G1)	NYISO		✓								
44.	Todd Gosnell (G6)	OPPD										✓
45.	Stephen Tankersley	Pacific Gas and Electric Co. (PGE)	✓									
46.	Alicia Daugherty (G1)	PJM		✓								
47.	Jack Gardner (G3) (G5)	Progress Energy Carolinas	✓									
48.	John Pinney (G3)	Progress Energy Florida	✓									
49.	Philip Riley (G4)	Public Service Commission SC									✓	
50.	Mignon L. Clyburn (G4)	Public Service Commission SC									✓	
51.	Elizabeth B. Fleming (G4)	Public Service Commission SC									✓	
52.	G. O'Neal Hamilton (G4)	Public Service Commission SC									✓	
53.	John E. Howard (G4)	Public Service Commission SC									✓	
54.	Randy Mitchell (G4)	Public Service Commission SC									✓	
55.	C. Robert Moseley (G4)	Public Service Commission SC									✓	

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
56.	David A. Wright (G4)	Public Service Commission SC									✓	
57.	John Wolfmeyer (G5)	SERC										✓
58.	Jerry Lindler (G5)	South Carolina E&G	✓									
59.	Roman Carter (G6)	Southern Transmission	✓									
60.	Charles Yeung (G1)	SPP		✓								
61.	Richard Dearman (I) (G5)	TVA	✓									
62.	Jeffrey S. Disorda	VELCO	✓									
63.	Jim Haigh (G6)	WAPA										✓
64.	Neal Balu (G6)	WPSR										✓
65.	Pam Oreschnick (G6)	Xcel Energy										✓

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 – IRC Standards Review Committee (IRC SRC)
G2 – NPCC CP9 Reliability Standards Working Group (NPCC CP9)
G3 – Progress Energy Carolinas/Progress Energy Florida (PGN)
G4 – Public Service Company of South Carolina (PSC SC)
G5 – SERC Vegetation Management Subcommittee (SERC VMS)
G6 – Southern Company Transmission
G7– MRO Members

Index to Questions, Comments, and Responses

1. **Do you agree there is a reliability need for the proposed modifications and review of the standard?**

Summary Consideration: Most commenters noted that while the FAC-003-1 Standard is technically adequate, they believed that clarification in the form of a technical white paper, and review of applicability parameters is warranted. Many of these commenters also agreed with the need to update the standard to conform to new procedural requirements and inclusion of compliance elements. The SDT shall consider producing a white paper to aid in clarifying the intent of the standard.

Question #1			
Commenter	**Yes**	**No**	**Comment**
AEP		☑	AEP believes that the current standard (when thoroughly read and understood) is completely adequate to maintain a reliable transmission system with minimum risk of vegetation-related outages.
Response: The team concurs that the technical elements are generally adequate and there is no reliability need to revise the standard. However all NERC standards must be updated to comply with new procedural requirements and inclusion of compliance elements. The Standard DT will address the issues raised in the FERC's March 16, 2007 Order 693 - Mandatory Reliability Standards for the Bulk Power System. The SDT shall consider producing a white paper to aid in clarifying the intent of the standard.			
Baltimore Gas & Electric		☑	I'm not convinced that the elements outlined in the proposal will improve reliability and have concerns that the proposed modifications may actually reduce the flexibility that is necessary to promote system reliability or to comply with local regulations. I would prefer to see more specifics in the proposal before supporting the modifications.
Response: The team concurs that the technical elements are generally adequate and there is no reliability need to revise the standard. However all NERC standards must be updated to comply with new procedural requirements and inclusion of compliance elements. The Standard DT will address the issues raised in the FERC's March 16, 2007 Order 693 - Mandatory Reliability Standards for the Bulk Power System. The SDT shall consider producing a white paper to aid in clarifying the intent of the standard.			
CenterPoint Energy		☑	CenterPoint Energy does not agree that a revision to the TVM standard is necessary from a reliability standpoint, and believes that the existing TVM standard is adequate for that purpose.
Response: The team concurs that the technical elements are generally adequate and there is no reliability need to revise the standard. However all NERC standards must be updated to comply with new procedural requirements and inclusion of compliance elements. The Standard DT will address the issues raised in the FERC's March 16, 2007 Order 693 - Mandatory Reliability Standards for the Bulk Power System. The SDT shall consider producing a white paper to aid in clarifying the intent of the standard.			
Central Maine Power		☑	The current Vegetation Management Standard FAC-003-1 has been crafted in such a way as to provide crisp measurable standards that when followed will provide a high level of power quality for the bulk power delivery system. However, clearances between

Question #1			
Commenter	**Yes**	**No**	**Comment**
			conductors and trees required to prevent tree related power outages must be consistent with each utility's established standards and if a transmission line passes through federal, state or locally managed areas this line placement should not impact the established clearances. Utilities should not be expected to negotiate clearances with multiple land managers. The IEEE 516 – 2003 table is an acceptable table to use as the minimum clearance to prevent a flash over and outages. FAC-003-1 is designed to be a reliability standard and the industry adheres to OSHA and ANSI standards to protect workers and the public. The IEEE 516 – 2003 table lists appropriate distances that should be used to measure compliance. The standard should continue to provide the flexibility for utility managers to increase "Clearance 2". The definition for right-of-way should be clarified to include only the area that is cleared and included as routine maintenance. We agree that there is a need to establish time horizons and clarify violation levels.
Response: The team concurs that the technical elements are generally adequate and there is no reliability need to revise the standard. However all NERC standards must be updated to comply with new procedural requirements and inclusion of compliance elements. The Standard DT will address the issues raised in the FERC's March 16, 2007 Order 693 - Mandatory Reliability Standards for the Bulk Power System, including a review of the definition for right-of-way. The SDT shall consider producing a white paper to aid in clarifying the intent of the standard.			
Duke Energy		☑	From a reliability perspective, the current standard contains appropriate requirements and measures to ensure the Transmission Owner's vegetation management program is implemented and managed to ensure the reliability of the transmission system. However the standard should be revised to address non-reliability related items that are in the SAR.
Response: The SAR DT agrees and thanks you for the comment.			
HQT		☑	It is our belief that the Standard in its current form does provide adequate provisions and drivers to minimize vegetation related outages and eliminate the likelihood of reoccurence of the August 14, 2003 blackout. However, it is recognized that the industry needs to consolidate its view on these provisions and we support the preparation of a "white paper" that will document the rationale concerning the requirements of the standard, as well as review certain aspects of the standard that have come into question.
Response: The SAR DT agrees and thanks you for the comment.			

Question #1			
Commenter	**Yes**	**No**	**Comment**
Hydro One Networks		☑	It is our belief that the Standard in its current form does provide adequate provisions and drivers to minimize vegetation related outages and eliminate the likelihood of reoccurence of the August 14, 2003 blackout. However, it is recognized that the industry needs to consolidate its view on these provisions and we support the preparation of a "white paper" that will document the rationale concerning the requirements of the standard, as well as review certain aspects of the standard that have come into question.
Response: The SAR DT agrees and thanks you for the comment.			
National Grid		☑	National Grid believes that compliance with all elements of the present Standard will result in TO's achieving the reliability objectives set forth in the Standard.
Response: The SAR DT agrees and thanks you for the comment.			
Northeast Utilities		☑	Proposed modifications do not increase the levels of reliability above what is already required in the current version of the Stnadard.
Response: The team concurs that the technical elements are generally adequate and there is no reliability need to revise the standard. However all NERC standards must be updated to comply with new procedural requirements and inclusion of compliance elements. The Standard DT will address the issues raised in the FERC's March 16, 2007 Order 693 - Mandatory Reliability Standards for the Bulk Power System. The SDT shall consider producing a white paper to aid in clarifying the intent of the standard.			
PGN		☑	Progress Energy Carolinas and Progress Energy Florida are providing an answer to the question as it relates to the reliability need. The current standard contains appropriate requirements and measures to ensure the Transmission Owner's vegetation management program is implemented and managed to ensure the reliability of the transmission system. In addition, we do not believe that a standard with a zero tolerance for vegetation-related outages in the ROW is in need of reliability-based revisions. However, we do recognize the need for a revision of the standard to address non-reliability related items that are in the SAR. Procedural items such as formatting and clarifications, such as the definition of right-of-way, need to be, and should be, addressed.
Response: The team concurs that the technical elements are generally adequate and there is no reliability need to revise the standard. However all NERC standards must be updated to comply with new procedural requirements and inclusion of compliance elements. The Standard DT will address the issues raised in the FERC's March 16, 2007 Order 693 - Mandatory Reliability Standards for the Bulk Power System. The SDT shall consider producing a white paper to aid in clarifying the intent of the standard.			

<table>
<tr><th colspan="4">Question #1</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td>SERC VMS</td><td></td><td>☑</td><td>The SERC VMS is providing an answer to the question as it relates to the reliability need. The current standard contains appropriate requirements and measures to ensure the Transmission Owner's vegetation management program is implemented and managed to ensure the reliability of the transmission system. In addition, we do not believe that a standard with a zero tolerance for vegetation-related outages in the ROW is in need of reliability-based revisions.

However the SERC VMS recognizes the need for a revision of the standard to address non-reliability related items that are in the SAR. Procedural items such as formatting and clarifications, such as the definition of right-of-way, need to be, and should be, addressed.</td></tr>
<tr><td colspan="4">Response: The team concurs that the technical elements are generally adequate and there is no reliability need to revise the standard. However all NERC standards must be updated to comply with new procedural requirements and inclusion of compliance elements. The Standard DT will address the issues raised in the FERC’s March 16, 2007 Order 693 - Mandatory Reliability Standards for the Bulk Power System. The SDT shall consider producing a white paper to aid in clarifying the intent of the standard.</td></tr>
<tr><td>CECD</td><td>☑</td><td></td><td>Modifications to capture the Commissions concerns must be addressed therefore these actions are appropriate.</td></tr>
<tr><td colspan="4">Response: The Standard DT will address the issues raised in the FERC’s March 16, 2007 Order 693 - Mandatory Reliability Standards for the Bulk Power System.</td></tr>
<tr><td>Dominion</td><td>☑</td><td></td><td>We support reinstating the 200kv threshold for reportable events.</td></tr>
<tr><td colspan="4">Response: The Standard DT will review applicability as requested by the FERC. See also the drafting team responses to question #2.</td></tr>
<tr><td>Entergy Corp.</td><td>☑</td><td></td><td>The existing FAC-003-1 is flawed and needs revision.</td></tr>
<tr><td colspan="4">Response: The SAR DT agrees that revisions of this standard are needed primarily to comply with new procedural requirements and inclusion of compliance elements as well as address issues raised in the FERC’s March 16, 2007 Order 693 – Mandatory Reliability Standards for the Bulk Power System.</td></tr>
<tr><td>FirstEnergy Corp.</td><td>☑</td><td></td><td>FirstEnergy agrees that clarification on select issues will aid the intent of this NERC Standard.</td></tr>
<tr><td colspan="4">Response: The SAR DT agrees and thanks you for the comment.</td></tr>
<tr><td>Florida Power & Light</td><td>☑</td><td></td><td>FPL believes the technical portion of the standard provides adequate reliability protection to the system. FPL also recognizes the need to re-format the standard to bring it into conformance with the latest version of the Reliability Standard Development Procedure and the ERO Sanctions Guidelines, to remove references to RRO in the standard and substitute a responsible entity and, add compliance elements such as time horizons, and</td></tr>
</table>

Question #1			
Commenter	**Yes**	**No**	**Comment**
			violation severity levels.
Response: The SAR DT agrees and thanks you for the comment.			
IESO	☑		
IRC SRC	☑		
ISO-NE	☑		
Manitoba Hydro	☑		The definition of ROW should be clarified. The definition of a critical line should not be kept to a particular voltage threshold. However, consideration could also then be given to exempting non-critical lines operating at higher voltage levels (>200kv). Electrical clearances should be consistent whether on Federal or non-Federal land.
Response: The standard DT will review the definition of ROW. The standard DT will review applicability parameters of this standard, taking into account the comments from stakeholders such as NU, National Grid, Manitoba Hydro, First Energy, and others. The SAR DT concurs with the commenter with respect to applying this standard to Federal and non-Federal lands. The standard DT will evaluate the suitability of a case-by-case approach.			
MRO	☑		
NYISO	☑		
PGE	☑		As stated in the SAR.
Response: The SAR DT agrees and thanks you for the comment.			
PSC SC	☑		
Southern Transm.	☑		We do not feel there is a reliability need for modifying the standard. However, we do agree certain modifications are needed to clarify procedural issues such as the amount of time allowed for taking corrective action when items are found to be out of compliance.
Response: The team concurs that the technical elements are generally adequate and there is no reliability need to revise the standard. However all NERC standards must be updated to comply with new procedural requirements and inclusion of compliance elements. The Standard DT will address the issues raised in the FERC's March 16, 2007 Order 693 - Mandatory Reliability Standards for the Bulk Power System. The SDT shall consider producing a white paper to aid in clarifying the intent of the standard.			
TVA	☑		The primary needs for mocdifications to this standard are in areas to address clarifications and formatting not reliability related issues.
Response: The SAR DT agrees and thanks you for the comment.			

2. **If you are a transmission owner, have you been provided a list from a Regional Entity (formerly RRO) of sub 200 kV critical transmission lines that must comply with FAC-003-1?**

Summary Consideration: During the March 2007 SAR DT meeting, the FERC indicated they had not been presented any evidence with respect to Regional Entity (RE) critical line determinations and asked whether such lists existed. This question was posed to ascertain whether REs have determined which lines below 200 kV are critical.

Some commenters reported that their RE (SERC, FRCC, RFC) have determined there are no critical transmission lines that are under 200 kV. Some commenters (NGrid, NU, HydroOne, HQT) indicated that a list was not provided by their RE (NPCC). A commenter (MRO) noted that a list was submitted to NERC. A commenter responded that their RE (WECC) has provided such a list. On the basis of this informal poll, the SAR DT's assessment is that further specificity may be needed to aid in identifying which <200kV transmission lines should come under the purview of this standard in an attempt to standardize this criteria.. The SDT shall take under consideration other applicability parameter criteria in addition to various stakeholder proposals.

Question #2			
Commenter	**Yes**	**No**	**Comment**
IRC SRC			n/a
NYISO			n/a
Baltimore Gas & Electric		☑	The reason that we do not have a list of critical lines from the RRO may be that we do not have any lines that fit the criteria.
Response: The SAR DT thanks you for your response.			
CECD		☑	SERC does not currently have any sub 200 kV critical transmission lines.
Response: The SAR DT thanks you for your response.			
CenterPoint Energy		☑	
Central Maine Power		☑	The "Northeast Power Coordinating Council Facilities Notification List" may not be the correct list to be used for this standard. FAC- 003-1 should set a clear expectation the each Regional Entity will provide their transmission owners a list of critical lines including any that may be less that 200KV. Will provide list once released from NPCC.
Response: The SAR DT thanks you for your response.			
Dominion		☑	
Duke Energy		☑	The SERC region has not identified any lines below 200kV to be critical to the electrical system in the region. Since no lines have been identified as critical to the region, no list has been provided to Transmission Owners.
Response: The SAR DT thanks you for your response.			
HQT		☑	We consider that it should be the Planning Coordinator role to determine the sub 200kV critical transmission lines and even for any transmission lines irrelevant of voltage level.

Question #2			
Commenter	Yes	No	Comment
			For that, it should follow an impact based methodology such as the one used in NPCC.
Response: The SAR DT thanks you for your response.			
Hydro One Networks		☑	
Manitoba Hydro		☑	
MRO		☑	The MRO We have not generated a list or criteria yet. We have submitted a draft criteria to NERC
Response: The SAR DT thanks you for your response.			
National Grid		☑	The Reliability Entity has not provided a list of sub 200 kV lines subject to compliance with FAC-003-1. The Standard became effective in February 2007, just 3 months ago. Having no list today should not imply that the RE or the Standard has failed in any way. National Grid suggests that a revised Standard should direct the RE to produce a list of "sub 200 kV critical transmission lines" within 6 to 12 months of adoption.
Response: The standard DT will review applicability parameters of this standard, taking into account the comments from stakeholders such as NU, National Grid, Manitoba Hydro, First Energy, and others.			
Northeast Utilities		☑	The Reliability Entity has not provided a list of facilities covered under FAC-003-1. This is not a fault of the RE as there has been no direction provided as to what factors or charateristics are required for sub-200kV lines to be included under the Standard. It is our position that the factors that will be used to develop the list of sub-200kV faciltities to be covered by the Standard be developed at the national level (NERC) and adopted by all RE's for consistency.
Response: The standard DT will review applicability parameters of this standard, taking into account the comments from stakeholders such as NU, National Grid, Manitoba Hydro, First Energy, and others.			
PGN		☑	The SERC and FRCC regions have not identified any lines below 200kV to be critical to the electrical system in the region. Since no lines have been identified as critical to the region, no list has been provided to Progress Energy Carolinas and Progress Energy Florida. (Please note our comments on this issue in question #4.)
Response: The SAR DT thanks you for your response.			
SERC VMS		☑	The SERC region has not identified any lines below 200kV to be critical to the electrical system in the region. Since no lines have been identified as critical to the region, no list has been provided to Transmission Owners. (Please note the subcommittee's comments on this issue in question #4.)
Response: The SAR DT thanks you for your response.			
TVA		☑	We detemined that there are no TVA lines below 200kv that must comply to this standard due to their criticial needs in SERC.

Question #2			
Commenter	**Yes**	**No**	**Comment**
Response: The SAR DT thanks you for your response.			
VELCO		☑	VELCO has not been provided a specific list of critical lines below 200 kV from the RE that need to be in compliance with FAC-003-1. VELCO suggests changing the wording in the standard to identify those lines affected as 200 kV and great or those defined as Bulk Power System facilities.
Response: The standard DT will review applicability parameters of this standard, taking into account the comments from stakeholders such as NU, National Grid, Manitoba Hydro, First Energy, and others.			
Entergy Corp.	☑		Yes, the Reliability Entity (SERC) has performed its duty in evaluating our transmission system. SERC has confirmed that Entergy has no lines operating below 200kV that are critical to system reliability. Entergy has received its "list," but the list is blank. With respect to applicability, it is inappropriate to set a blunt voltage level criterion for determining which transmission lines are critical to bulk system reliability. There is no basis in engineering or in fact for voltage-based categories of applicability. Many lines operating at 200kV and higher essentially serve only local load, and there may in fact be some lines operating below 200kV where the standard should be applied. Many lines of all voltages are redundant and do not even impact local load during an outage. Therefore, the voltage criterion is overly broad. To support this statement, Entergy supplies the following facts: First, during the aftermath of Hurricanes Katrina and Rita, Entergy had (59) 230kV and 500kV lines out of service simultaneously. Additionally, Entergy had (85) 115kV and 161kV lines out of service simultaneously. During the aftermath of Hurricane Rita, Entergy had (41) 230kV and 500kV lines out of service simultaneously. Additionally, Entergy had (124) 115kV and 161kV lines out of service simultaneously. Dispite this overwhelming combination of simultaneous outages, no system-wide cascading blackout was initiated. Only local load was lost during restoration. This illustrates that Standard FAC-003-1, as it currently stands placing so much focus and penalty on even single-contingency outages, is overbroad, arbitrary and capricious. Second, each year the Entergy transmission system (like all other large electric utilities) suffers numerous outages from a great number of different sources: material defects, rot and decay, animal damage, human damage, extreme wind, lightning and, vegetation. Over the years 2001 through 2006, 927 transmission lines suffered 5,688 outages from a variety of sources. Vegetation outages accounted for 7.14% of those outages. Each

Question #2			
Commenter	**Yes**	**No**	**Comment**
			utility is unique, but these numbers are not unusual for a transmission system comprising 15,000 miles of line. Dispite this large number of outages, no cascading system black out has been intiated. Finally, Entergy has had as many as 17 transmission lines outaged from a single tornado event without even losing service to local load. Standard FAC-003-1 assigns too much risk to outages in general, and too mush risk to vegetation outages in particular. NERC and the regional reliability entities should define performance criteria that specifically define certain contingencies and certain undesireable outcomes that would classify a line as truly critical to bulk system reliability. The modeling software necessary to do this is readily available and already in use today by the Reliability Entities and their subject utilities. If FERC has concerns about potentially devistating (albeit rare) combinations of multiple simultaneous line outage contingencies, the REs can define strict criteria for multiple contingencies. With respect to lines that result in IROLs and SOLs, these lines can also be identified with specificity, without resorting to blunt voltage distinctions. Defining system-critical lines too broadly is actually detrimental to FERC's reliability goals. It dilutes the resources available to maintain reliability on those lines that truly affect system reliability. Utilities should employ a more focused and intelligent approach to targeted reliability. Such an approach would have benefits to the users of the transmission system and to the ratepayers that pay for it.
Response: The standard DT will review applicability parameters of this standard, taking into account the comments from stakeholders such as yourself and others.			
Florida Power & Light	☑		
PGE	☑		Provided from WECC
Response: The SAR DT thanks you for your response.			
AEP	☑	☑	Of the three regions in which AEP has transmission facilities, only one RE has provided a listing of sub-200 kV facilities of what we consider applicable under this standard.
Response: The SAR DT thanks you for your response.			
FirstEnergy Corp.	☑	☑	ReliabilityFirst, the Reliability Entity (formerly the RRO) was requested to provide a list of lines below 200 kV deemed as critical transmission lines that must comply with FAC-003-01. ReliabilityFirst responded "there are no lines below 200kV deemed as critical

Question #2			
Commenter	**Yes**	**No**	**Comment**
			infrastructure".
Response: The SAR DT thanks you for your response.			
Southern Transm.	☑	☑	We are not really sure how to answer this question. The Regional Entity has not sent us a list, but they have advised us that we do not have any sub 200 kv critical transmisison lines that must comply with FAC-003-1.
Response: The SAR DT thanks you for your response.			

3. If you are a transmission owner would you provide your methodology for determining clearance 1 and clearance 2? (As described in FAC-003-1 R1.2.1 and R1.2.2) If so, please attach.

Summary Consideration: This question was posed to poll transmission owners with respect to determination of Clearance 1 and Clearance 2 requirements. This information was sought to obtain examples of how industry members determine Clearance 1 since it is a qualitative requirement. Clearance 2 information was sought to evaluate the application of components of IEEE 516.

Of the 15 respondents to this poll question, some provided summary methodology for determining their Clearance 1 and Clearance 2, others have indicated that a methodology exists and is available upon request. On the basis of these responses to the poll question, the SDT shall consider reviewing IEEE 516 components to affirm their suitability in this standard and this information can assist in a white paper.

Question #3			
Commenter	**Yes**	**No**	**Comment**
IRC SRC			n/a
NYISO			n/a
SERC VMS			This question does not apply to the SERC EC Vegetation Management Subcommittee.
Response: The SAR DT thanks you for your response.			
Baltimore Gas & Electric		☑	
Central Maine Power		☑	The clearance 2 was taken directly from IEEE Table 516 – 2003. Clearance 1 is based on "Appendix C – ISO New England Right of way Vegetation Management Standard".
Response: The SAR DT thanks you for your response.			
Florida Power & Light		☑	
National Grid		☑	Detailed methodology is not attached. In summary, National Grid used Table 5 IEEE Section 516 for determing clearance 2. These data for each voltage class were rounded to the next higher whole number. Clearance 1 was determined by adding the clearance 2 distance, conductor sag distance, and anticipated tree growth over the maintenance cycle.
Response: The SAR DT thanks you for your response.			
PGN		☑	Progress Energy has an individual on the Drafting Team and will share the Progress Energy Florida clearance Tables with the team.
Response: The SAR DT thanks you for your response.			
VELCO		☑	VELCO has defined Clearance 1 as the maximum allowed vegetation heights (12ft high) at time of maintenance. This maximum height has evolved from experience with regional

Question #3			
Commenter	**Yes**	**No**	**Comment**
			growth rates and other factors. VELCO's Clearance 2 is determined by the New England ISO's Operating Procedure 3, which is slightly more stringent than IEEE 516.
Response: The SAR DT thanks you for your response.			
AEP	☑		For Clearance 1, AEP has chosen to use the minimum approach distances set forth in ANSI Tree Care Standard Z133.1 (rev. October 2000) for persons other than qualified line-clearance arborists and qualified line-clearance arborist trainees. For Clearance 2, AEP utilizes the Z133.1 minimum approach distances for qualified line clearance arborists and qualified line-clearance arborist trainees.
Response: The SAR DT thanks you for your response.			
CenterPoint Energy	☑		CenterPoint Energy has developed a methodology to determine clearance 1 and clearance 2 as described in FAC-003-1 R1.2.1 and R1.2.2. This methodology is included in a document titled "Specification for Transmission Vegetation Management Program" dated February 2007. Section 5.1 of that document covers NERC Clearance 1, and Section 5.2 covers NERC Clearance 2. Text and Tables from both Sections 5.1 and 5.2 are shown below: 5.1 NERC CLEARANCE 1 5.1.1 The appropriate clearance to conductors at the time of vegetation management work is established as Clearance 1 in accordance with NERC Standard FAC-003-1 Requirement R1.2.1. 5.1.2 Clearance 1 is determined by considering transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, the effects of wind velocities on conductor sway, and the anticipated average growth rate of the prevalent tree species within the Company's service area over a 5-year period. 5.1.2.1 The minimum clearance distance of IEEE Standard 516-2003 Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap, is a component of Clearance 1. 5.1.3 Table 5.1 contains the horizontal clearance components and nominal values for Clearance 1, and Table 5.2 contains the vertical clearance components and nominal values for Clearance 1. Table 5.1

Question #3			
Commenter	**Yes**	**No**	**Comment**
			NERC Clearance 1: Horizontal Clearance, feet Horizontal Clearance Component, Nominal Voltage p-p 69kV 138kV 345kV Electrical Clearance (1) 2.46 2.95 4.40 Average 5-Year Horizontal Tree Growth 12.00 12.00 12.00 Average Mid-span Conductor Sway (2) 5.98 8.13 10.04 Total 20.44 23.08 26.44 Nominal Horizontal Value (3) 20 23 26 (1) Based on IEEE 516-2003 Table 5 for 69kV & 138kV and Table 7 for 345kV (2) Based on NESC C2-2007 Rule 233A(1) (3) May be reduced for site specific tree species or conductor span configuration but not less than Clearance 2. Table 5.2 NERC Clearance 1: Vertical Clearance, feet Vertical Clearance Component, Nominal Voltage p-p 69kV 138kV 345kV Electrical Clearance (1) 2.46 2.95 4.40 Average 5-Year Vertical Tree Growth 15.75 15.75 15.75 Average Conductor Final Sag Increase (2) 7.52 9.01 10.24 Total 25.73 27.71 30.39 Nominal Vertical Value (3) 26 28 30

Question #3			
Commenter	**Yes**	**No**	**Comment**
			(1) Based on IEEE 516-2003 Table 5 for 69kV & 138kV and Table 7 for 345kV (2) Based on NESC C2-2007 Rule 233A(1) (3) May be reduced for site specific tree species or conductor span configuration but not less than Clearance 2. 5.2 NERC CLEARANCE 2 5.2.1 The minimum radial clearance to prevent flashover between vegetation and conductors is established as Clearance 2 in accordance with NERC Standard FAC-003-1 Requirement R1.2.2. 5.2.2 Clearance 2 is determined by considering transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Clearance 2 is a radial clearance, so the vertical component and the horizontal component are both calculated, and the largest clearance is selected as the prevailing clearance for Clearance 2. 5.2.2.1 The minimum clearance distance of IEEE Standard 516-2003 Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap, is a component of Clearance 2. 5.2.3 Table 5.3 contains the horizontal clearance component, Table 5.4 contains the vertical clearance component, and Table 5.5 contains the prevailing nominal values for Clearance 2. Table 5.3 Horizontal Clearance Component, feet Horizontal Clearance Component, Nominal Voltage p-p 69kV 138kV 345kV Electrical Clearance (1) 2.46 2.95 4.40 Average Mid-span Conductor Sway (2) 5.98 8.13 10.04

Question #3			
Commenter	**Yes**	**No**	**Comment**
			Total 8.44 11.08 14.44 Nominal Horizontal Value (3) 8 11 14 (1) Based on IEEE 516-2003 Table 5 for 69kV & 138kV and Table 7 for 345kV (2) Based on NESC C2-2007 Rule 233A(1) (3) May be reduced for site specific tree species or conductor span configuration but not less than Clearance 2. Table 5.4 Vertical Clearance Component, feet Vertical Clearance Component, Nominal Voltage p-p 69kV 138kV 345kV Electrical Clearance (1) 2.46 2.95 4.40 Average Conductor Final Sag Increase (2) 7.52 9.01 10.24 Total 9.98 11.96 14.64 Nominal Vertical Value (3) 10 12 15 (1) Based on IEEE 516-2003 Table 5 for 69kV & 138kV and Table 7 for 345kV (2) Based on NESC C2-2007 Rule 233A(1) (3) May be reduced for site specific tree species or conductor span configuration but not less than Clearance 2. Table 5.5 NERC Clearance 2: Minimum Radial Clearance to Prevent Flashover, feet Nominal Voltage p-p 69kV 138kV 345kV 10 12 15

Question #3			
Commenter	**Yes**	**No**	**Comment**
Response: The SAR DT thanks you for your response.			
Entergy Corp.	☑		Entergy defines four sets of clearances for vegetation approach to transmission lines. The first set of clearances is the Vegetation Pruning Distance. This is the clearance to be achieved at the time of vegetation management work which vegetation management employees and contractors complete as part of this program. This distance varies with each line, but is set to be the EDGE OF ROW in each case. (This clearance is referred to as "Clearance 1" in the NERC Vegetation standard FAC-003-1, Cf B.R1.2.1). The second set of clearances is the Vegetation Growth Alert Distance. This is the approach distance that triggers an alert to the Asset Management vegetation management employees that vegetation maintenance is required. Vegetation spotted on an aerial inspection that encroaches upon this clearance is noted on the inspection for future scheduling of pruning. The third set of clearances is the Minimum Energized Pruning Distance. This is the minimum approach distance vegetation can have to energized transmission lines and still be pruned without an outage on the energized transmission line, in accordance with OSHA safety guidelines. Any vegetation that encroaches on this minimum distance must be pruned, and must be pruned during an outage on the associated transmission line. The fourth set of clearances is the Minimum Vegetation Approach Distance. This is the absolute minimum radial approach distance to prevent flashover between vegetation and overhead ungrounded supply conductors. Under this program, vegetation should never encroach these minimum approach distances. Vegetation must be pruned prior to reaching this distance and must be pruned with an outage on the transmission line. (This distance is referred to as "Clearance 2" in the NERC vegetation standard, FAC-003-1, Cf B.R1.2.2.) These clearance distances are based upon those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (Guide for Maintenance Methods on Energized Power Lines) and as specified in Table 5. Under this program, vegetation can encroach the Vegetation Growth Alert Distance and the Minimum Energized Pruning Distance, but it shall not encroach upon the Minimum Vegetation Approach Distance.
Response: The SAR DT thanks you for your response.			

Question #3			
Commenter	**Yes**	**No**	**Comment**
FirstEnergy Corp.	☑		For R1.2.1 (Clearance 1), FirstEnergy used our existing specification requirement "for minimum clearance to be achieved at locations with an easement or other restriction" to define the minimum acceptable clearance. For R1.2.2 (Clearance 2), FirstEnergy uses the IEEE 516-2003 standard as the minimum as referenced in FAC-003-01. This is the minimum clearance under all operating conditions. FirstEnergy believes this is an appropriate definition.
Response: The SAR DT thanks you for your response.			
HQT	☑		HQT clearance methodology is not specifically based on the value specified in Clearance 1 and Clearance 2. HQT TVMP is such organized that vegetation management work minimize costs for line clearing and brush control while preventing outages from vegetation cause. As such, staff qualifications required to work near energized facilities are less than under the absolute minimum as stipulated in IEEE 516-2003, and in most cases, the work is less labour and equipment intensive. However clearances are never less than the absolute minimum stipulated in FAC-003-1 (R1.2.2). The above provides the basic approach used at HQT. If the Standard Drafting Team would like a copy of the HQT approach and methodology, this could be provided.
Response: The SAR DT thanks you for your response.			
Hydro One Networks	☑		Hydro One clearance standards are based on the Ontario Health and Safety Act (OHSA) clearances rather than the absolute minimum specified in Clearance 2. OHSA clearances at time of work minimize costs for line clearing and brush control. By maintaining OHSA clearances during normal working conditions, staff qualifications required to work near energized facilities are less than under the absolute minimum as stipulated in IEEE 515-3003, and in most cases, the work is less labour and equipment intensive. As part of work planning, qualified staff determine the amount of vegetation that has to be removed to achieve OHSA clearances at the time of the next scheduled work. As well, provisions are built into the clearances at time of work to account for conductor and tree movement during adverse weather conditions. The objective is to provide OHSA clearances under adverse conditions, but these are not always achieved, however clearances are never less than the absolute minimum stipulated in FAC-003-1. The above provides a description of our planning process. If the Standard Drafting Team would like a copy of the Hydro One standard, this can be provided.
Response: The SAR DT thanks you for your response.			

Question #3			
Commenter	**Yes**	**No**	**Comment**
Manitoba Hydro	☑		Clearance 1 was developed based on the limits of approach for non-qualified people (public). At a minimum, we would clear beyond this distance during vegetation control activities. Our cycle times and management approach are adjusted for this distance, taking into account growth rates. The values will vary depending on voltage class. Clearance 2 is based on internal design standards that take into account our understanding of switching surge values for our system. The values used are more conservative than IEEE 516-2003.
Response: The SAR DT thanks you for your response.			
MRO	☑		n/a
Northeast Utilities	☑		The methodology for determining clearance 2 is based on the requirements of FAC-003-1. The IEEE Section 516 has been considered the base minimum limits for clearances as provided under FAC-003-1 R.1.2.2. Clearances used for R.1.2.1 on the NU Transmission System comply with the requirements of ISO-NE Operating Procedure OP-3, that provides clearance levels required at the time of vegetation trimming or clearing under the various transmission voltages.
Response: The SAR DT thanks you for your response.			
PGE	☑		Will be provided to the SARDT in a separate attachment[TH1].
Response: The SAR DT thanks you for your response.			
Southern Transm.	☑		IEEE 516-2003, Section 4.2.2.3 was adopted as the minimum allowable distance for Clearance 2, with the expectation that work would normally occur prior to Clearance 2 reaching the minimum allowable distance. Clearance 1 was determined by using the Clearance 2 value and adding a growth buffer. Sagging of conductors and their movement in wind was then considered to ensure the growth buffer is adequate.
Response: The SAR DT thanks you for your response.			
TVA	☑		We utilize a clearance 2 based on IEEE 516 2003 Table 5 criteria. Our Clearance 1 is a greater amount to allow for growth between clearing and next inspection or clearance activities. We will provide our tables is requested.
Response: The SAR DT thanks you for your response.			

4. **Are there any other comments regarding the standard, its possible modifications or the SAR?**

Summary Consideration:
The comments were mixed with regard to:
- Whether reporting of Category 3 outages are necessary.

Most that commented agreed that:
- The 200kV applicability threshold could be clarified and the SAR DT deemed a review of applicability parameters is desirable.
- A consistent approach to both federal and non federal lands is desirable.
- A review of the definition of ROW is desirable.
- Components of the IEEE 516 standard are suitable.
- The exclusion of major disaster related events is appropriate.
- The inclusion of compliance elements and other procedural updates of the standard are needed.
- The development of a technical white paper is desirable.
- The standard DT should review the need for Requirement R4.

On the whole, the comments are supportive of the SAR as written and the SAR DT have made no changes to the second draft of the request.

Question #4			
Commenter	**Yes**	**No**	**Comment**
CenterPoint Energy		☑	
Manitoba Hydro		☑	
PSC SC		☑	
Southern Transm.		☑	We appreciate the efforts of the SAR Drafting Team.
AEP	☑		The SAR directs the SDT to collect and analyze outage data as part of an effort to define clearances for transmission lines on federal and non-federal lands. AEP believes that the analysis of outage data will be meaningless and unproductive. The SAR directive presupposes a cause-and-effect relationship between vegetation-related outages and federal/non-federal land status. On the contrary, AEP believes that vegetation-related data is more indicative of the effectiveness of the utility's VM program, in spite of onerous and inordinately expensive measures required on federal lands.
Response: The standard DT looks to receive the results of the ERO analysis and use it in developing the standard.			

Question #4			
Commenter	**Yes**	**No**	**Comment**
Ameren	☑		Ameren does not agree that each of 11 items listed in the SAR are necessary to improve reliability. The following comments are offered for each of the 11 items identified in the SAR detail description: 1. Standard Applicability: Ameren disagrees with revising the 200 kV threshold for determining facilities subject to this standard. Extending the requirements to lines other than those >200kV will dilute the focus on those lines that impact grid reliability and shift attention to facilities, <200kV. Utilities generally have an incentive to maintain reliability on lines less than 200kV. State commissions and customer expectations for reliable service provide this incentive. While many facilities above 200kV directly support customer load, transmission lines below 200kV primarily support customer load, and interruptions to those facilities reduces load on the grid. The majority of transmission facilities below 200 kV also have significantly different design/construction/operating characteristics and have not been cited as impacting bulk power system reliability. For example, the Final Report on the August 14, 2003 Blackout in the United states and Canada: Causes and Recommendations April 2004 by the U.S.-Canada Power System Outage Task Force and all referenced major blackouts (pages 103-115) in that report, cited only outages which involved vegetation at line voltages above 200kV. Generally applying requirements that are appropriate for >200kV lines to lines less than 200kV will result in significant documentation and reporting of items such as restrictions, mitigation plans, off right-of-way vegetation-related outage investigation/ information and other issues, all of which dilutes the focus on lines that directly impact bulk power system reliability. Revising the standard to use general criteria or broad language for defining "Bulk Power System" transmission lines covered by the standard is a "one size fits all" approach. If that approach were taken, the standard would cover a significant number of transmission lines that have no direct impact on bulk power system reliability under standard planning/operating conditions, resulting in a significant cost burden for electric customers without improving "grid" reliability. Ameren believes that the applicability provision of the standard should focus attention of the standard only on the transmission lines below 200kV that directly impact "Bulk Power System" reliability, as the current version requires.

Question #4			
Commenter	**Yes**	**No**	**Comment**
			Ameren recognizes some validity in the Commission's concern; Ameren recommends that the applicability provision of this standard should be revised only if existing system design, planning or operating reliability criteria and parameters are considered as a basis for defining the applicability of the standard. Ameren recommends each Regional Entity (RE) determine applicability of FAC-003 to those lines within the region that are between 100kV and 200KV, if, and only if, they are identified as operationally significant elements of Interconnection Reliability Operating Limits ("IROLs"). That is, any facility below 200kV that by itself would cause an Interconnected Reliability Limit Violation should the facility be outaged. 2. Issue of Clearances (Federal vs Non-Federal Lands): FAC-003-1 presently requires the transmission owner (TO) "identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway." The intent of this requirement is to ensure adequate clearances to prevent vegetation related outages. Ameren believes that only the TO has the technical information required to determine the clearances that are necessary at the time of VM work and that any "federal lands exemption" to clearances will result in inadequate clearances for the existing conditions. Consistency in application of the TO's clearance requirements, not exceptions, is the only assurance in providing a uniform and reliable electrical system to meet the nation's current and future energy demands. Any exception for a case by case clearance approach to determine vegetation management activities/clearances on Federal lands will continue to drive inconsistency and/or delays associated with vegetation management decisions being driven by diverse vegetation management practices/beliefs and staff changes at the local level of Federal agencies. Vegetation-related outages have occurred on Federal lands as a result of this case by case approach, and if "Bulk Power Transmission System" lines continue to be addressed on a "case by case" basis on National Forest Service (or any other Federal lands), those lines will potentially be subject to a higher risk for vegetation-related outages, resulting in reduced reliability for the "Bulk Power System". Ameren believes that reliability of the "Bulk Power System" should have the same focus on Federal and private lands and that the EEI MOU with federal agencies is the

Question #4			
Commenter	**Yes**	**No**	**Comment**
			appropriate vehicle for TO's to identify clearance variances on Ferderal lands, not exemption language in the standard. The standard should not be used as a mechanism by federal agencies to impose variances to proven vegetation management practices and clearances. 3. Defining Right-of-Way: Ameren agrees that it is appropriate to further address the definition of "right-of-way". Corridor widths beyond design clearance requirements have been acquired for a variety of reasons in the past; future use, property line buffers, etc. Vegetation in those areas that would normally fall outside of the area necessary for operation of the facility should not be considered or treated different than vegetation that is outside of a defined easement/permit area that is designed for the reliable operation of an existing single line corridor. 4. IEEE Standard for Minimum Clearances: Ameren disagrees with objections to the use of the IEEE 516-2003 clearance as the minimum acceptable distances for "Clearance 2". The IEEE 516-2003 tables are appropriate for defining the minimum acceptable clearances to prevent flashover between conductors and vegetation under all rated electrical operating conditions. FERC staff references ANSI Z-133 which is a safety standard that addresses worker safety as well as the safety of the general public. As such, the purpose of ANSI Z-133 is to address worker safety and is not focused on transmission line reliability, which is the purpose of FAC-003-1. OSHA, NESC and other related safety standards have clearances in excess of IEEE 516-2003. Those clearances are clearly focused on safety issues and will still apply to other aspects of design and operation of electric facilities (such as public and worker safety) but are not appropriate to be referenced in a vegetation management reliability standard. 5/6/7. Procedural Items: Ameren agrees that the procedural items related to formatting RRO references and additional compliance elements should be addressed by the standard drafting team. 8. Technical Reference Materials:

Question #4			
Commenter	**Yes**	**No**	**Comment**
			Ameren agrees that a "white paper" that defines the technical basis for the standard is appropriate to avoid the potential for differences in interpretation of the standard's requirements during the various region's audit processes. 9. Category 3 Outages: Since the right to control off right-of-way vegetation is generally beyond control of the transmission owner Ameren believes that the reporting of category 3 outages should be removed from the requirements. 10. Requirement R4: Ameren believes that requirement R4 should be deleted from the standard, based on the ERO formation and the process for delegation of authority to the regional entities. 11. Reporting Exemptions: Ameren believes that the reporting requirement exemptions for natural disasters should include all categories of outages. It would, for example, be difficult, without delaying restoration efforts, to determine if the vegetation from high winds, hurricanes, tornadoes, etc. is from on or off the "right-of-way".

Response:

1. The standard DT will review applicability parameters of this standard, taking into account the comments from stakeholders such as NU, National Grid, Manitoba Hydro, First Energy, and others.
2. The SAR DT concurs with the commenter with respect to applying this standard to Federal and non-Federal lands. The standard DT will evaluate the suitability of a case-by-case approach.
3. The standard DT will review the definition of ROW.
4. The SAR DT agrees with the commenter and recognizes that sections of IEEE 516 standard pertaining to minimum air insulation distances are applicable in determining minimum vegetation clearances to prevent flashovers.
5. NERC standards must be updated to comply with new procedural requirements and must include compliance elements.
6. See #5
7. See #5
8. The SDT shall consider producing a white paper to aid in clarifying the intent of the standard.
9. The SAR indicates that the Standard Drafting Team will review reporting criteria for Category 3 outages and will review the reporting requirement of Category 3 outages in R.3 and R.4.

Question #4			
Commenter	**Yes**	**No**	**Comment**
10. The standard DT will consider deletion of R.4. 11. The standard DT will review the reporting exemptions to include all category outages under major disasters in Requirement R3.2.			
Baltimore Gas & Electric	☑		We completely disagree with the proposal to eliminate reporting or off-right-of-way tree outages. In reality, off-R/W outages can cause many of the same problems that on R/W outages do if they were to occur at the most inappropriate time. Granted that they typically do not occur at times of peak load, but they could. Moreover, many off-R/W tree outages are preventable and should be addressed before they occur.
Response: The SAR indicates that the Standard Drafting Team will review reporting criteria for Category 3 outages and will review the reporting requirement of Category 3 outages in R.3 and R.4.			
CECD	☑		CECD supports continuing to use the 200kV threshold for determining applicability of vegetation management criteria. If the standard is deemed to apply to lower voltages these should only be critical lower voltage transmission facilities as determined by the Regional Entities's. CECD would also encourage the drafting team to clarify that the Vegetation Management standards are not applicable to generator interconnection facilities. In the registration process due to the NERC functional definitions, Generation Owners/Operators are required to register as Transmission Owners/Operators because of step-up transformers and other associated interconnection equipment that was not intended to be subject to the Vegetation Management program.
Response: The standard DT will review applicability parameters of this standard, taking into account the comments from stakeholders such as NU, National Grid, Manitoba Hydro, First Energy, and others. As a registered transmission owner this standard is applicable. Registration matters should be referred to the NERC organization certification program and the related regional entity.			
Central Maine Power	☑		The standard FAC-003-1 is intended to create a frame work that will ensure a uniform level of reliability and at the same time must allow transmission owners to meet this objective using efficient and cost effective programs. To this end utilities must have the ability to implement "Clearance 1" distances consistently throughout their service areas. The standard should remain focused only on 200 KV and above lines or lines listed as critical by the Regional Entity. Inspection cycles are sufficient as listed the current version and allow flexibility to meet local variability in growth rates and other conditions. Concerns with inspection cycle length can be addressed in the compliance area.

Question #4			
Commenter	**Yes**	**No**	**Comment**
Response: The SAR DT thanks you for your comments. The standard DT will review applicability parameters of this standard, taking into account the comments from stakeholders such as yourself and others. The FERC is no longer indicating a need to develop a requirement for a minimum inspection cycle (March 16, 2007 Order 693) and stakeholders indicated they did not support this change, so it was removed from the SAR.			
Dominion	☑		In response to Stakeholder item #11, we do not support exempting Category 1 or Category 2 events that occur during natural disasters.
Response: A majority of the industry stakeholder comments support natural disaster exemptions.			
Duke Energy	☑		Regarding the Order 693 items, the applicability provision of the standard should focus attention of the standard only on the transmission lines 200kV and above, and those lines below 200kV that directly impact "Bulk Power System" reliability, as the current version of FAC-003 requires. Each Regional Entity (RE) must determine applicability of FAC-003 to those lines within the region that are less than 200kV. For example, transmission lines below 200kV should be considered within the scope of FAC-003 if they are identified as operationally significant elements of Interconnection Reliability Operating Limits ("IROLs"); i.e. an outage of the facility would cause an Interconnection Reliability Limit Violation. The Standard DT should address the issue of the necessity of maintaining consistent clearances for lines on both federal and non-federal lands. We agree with the use of the IEEE 516-2003 standard for for defining the minimum acceptable clearances to prevent flashover between conductors and vegetation under all rated electrical operating conditions. We believe that the reporting requirement exemptions for natural disasters should include all categories of outages.
Response: The standard DT will review applicability parameters of this standard, taking into account the comments from stakeholders such as NU, National Grid, Manitoba Hydro, First Energy, and others. The SAR DT concurs with the commenter with respect to applying this standard to Federal and non-Federal lands. The standard DT will evaluate the suitability of a case-by-case approach. The SAR DT agrees with the commenter and recognizes that sections of IEEE 516 standard pertaining to minimum air insulation distances are applicable in determining minimum vegetation clearances to prevent flashovers.			

Question #4			
Commenter	**Yes**	**No**	**Comment**
The standard DT will review the reporting exemptions to include all category outages under major disasters in Requirement R3.2.			
Entergy Corp.	☑		The policy to increase sanctions based on a finding of an "intentional economic decision to violate the standard" is ill-concieved: 1. Every transmission line outage that has ever occured could have been avoided if more money had been spent on SOMETHING, SOMWHERE. 2. No utility has an unlimited budget, so decisions based on risk, cost and benefit are made every day. 3. After the outage, the localized initiating cause will appear so trivial and inexpensive that it would seem that it could easily have been fixed in advance. 4. Therefore, reviewers could conclude that EVERY outage (a defacto violation of the standard), is the result of an "economic decision to violate the standard." Economic choices are a necessary and natural part of doing business, and do not necessarily imply the existence of malicious motives or wrong-doing. The current policy is going to create unnecessary costs to ratepayers, even to avoid inconsequential outages.
Response: The compliance sanctions guideline addresses the matter of willful noncompliance. Refer to the Compliance program with respect to this issue. However the standard DT and Compliance Elements DT will review and assign Violation Severity Levels when modifying FAC-003-1.			
FirstEnergy Corp.	☑		The definition of Right-Of-Way requires modification to clarify it is the width required by engineering to operate the line. This may or may not be the legal Right-of-Way. (See previously submitted comments submitted by FE in Feb 2007 for more details).
Response: The standard DT will review the definition of ROW.			
Florida Power & Light	☑		For the record FPL re-emphasize its comments from the previous FAC 003-1 SAR. Requirement 3.2 exempts reporting of outages from outside the ROW when natural disasters such as tornados or hurricanes occur. Our experience with numerous hurricanes indicates that all outages during these types of events should be exempt. The focus in these situations is to get the lines back in service and restore customers. There is insufficient manpower to adequately complete the forensics necessary to determine an accurate root cause. It is not uncommon to find vegetation debris in the lines or downed trees on the ROW in this situation. In most cases it is not possible to determine the original location of these trees.

Question #4			
Commenter	**Yes**	**No**	**Comment**
			In the compliance section of the document a transmission owner becomes non compliant with a single category 1 or 2 outage. This occurs regardless of the circumstances. A non compliant penalty for a single outage in a situation where no customers were affected and the system could not have been compromised is not reasonable. It is also not an indicator of a poorly maintained system. We agree that several Category 1 or 2 interruptions could be an indicator of neglect but one is not. We recommend that the compliance section be reviewed with this in mind.
Response: The SDT will review the reporting exemptions to include all category outages under major disasters in Requirement R3.2. The SDT and Compliance Elements DT will review and assign Violation Severity Levels when modifying FAC-003-1. Note that the levels of non-compliance that are in the approved version of FAC-003 will be replaced with violation severity levels.			
HQT	☑		Here are some general comments on the SAR: 1. In the purpose section of the SAR, item 1, we don't understand the substitution of BPS by «electric transmission system»; it seems like there is a will to make the Standards applicable to more than the BPS. It is our understanding that NERC Standards are aimed at the reliability of the BPS. The term BPS should be retained and instead of modifying the SAR to widen the applicability, the Standard itself should be modified to specifically used the term BPS in item A.3. 2. In the detailed description section, item 1, sub-bullet, it is written that: "...the SDT may consider other criteria in determining applicability of the Standard to sub 200 kV lines...". We think that in item 4.3 (Applicability) of the existing Standard, there is already the possibility of applying the Standard to sub 200 kV lines if determined by RRO. This could be reworded by saying: "...as determined by a methodology to define BPS element"; such as the one used by NPCC. 3. We noticed that most Definitions (e.g. RC, IA, PC, RP, TP, TOP, DP, GO, GOP, PSE, MO (not even in the Glossary), LSE) used to described the Reliability Functions in the SAR form, are somewhat different than those used in the Glossary of Terms approved with the Standards deposited at the FERC. For consistency, if the definition needs to be changed, this should be done through the right process, not just casually in the SAR Form. 4. Also, although the title in that same section of the SAR form refers to Reliability Functions, these are in fact the Responsible Entity that performs those functions; maybe a correction in the SAR form would be necessary.

Question #4			
Commenter	**Yes**	**No**	**Comment**
Response: 1. The SAR DT used 'Bulk Electric System' because that is the term defined in the NERC Glossary. 2. The standard DT will review applicability parameters of this standard, taking into account the comments from stakeholders such as NU, National Grid, Manitoba Hydro, First Energy, and others. Furthermore the standard DT will ensure that any new terms defined for use in this standard will also be added to the Glossary of Terms. 3. The standard DT will ensure that any new terms defined for use in this standard will also be added to the Glossary of Terms. the drafting teams were directed to use the definitions for the functional model entities in the version of the Functional Model just approved by the BOT in February, 2007. The glossary will be updated to include the revised definitions for the functional entities. 4. Thanks for the comment.			
Hydro One Networks	☑		We believe from a transmission system perspective, category 3 outages are no different than many of the other types of outages that take place on the system, such as hardware failures, lightning damage and station equipment outages to name a few. It is our understanding that there is no requirement to report these "other" outages, which makes one wonder why the tree related outages that originate off the right of way need to be reported. We are not diminishing the importance of category 3 outages, but from a system cascading perspective, these outages are no more important than other line or station outages, and are fewer in number than the "other" random outages. To initiate system cascading as occurred during August 14, 2003, a number of the random outages would have to coincide to cause a wide spread system event, which in our opinion is a very low probability occurrence. On the other hand, a category 1 outage can occur as a result of any system disturbance should there be deficiencies in clearances to vegetation, as such the importance of category 1 outages is apparent and reporting is appropriate. We support the review concerning the need to report category 3 outages and that the ultimate decision should be based on reporting rules that take into consideration the broader topic of reliability, rather than just vegetation related outages.
Response: The SAR indicates that the Standard Drafting Team will review reporting criteria for Category 3 outages and will review the reporting requirement of Category 3 outages in R.3 and R.4.			
IESO	☑		1. The SAR indicates that a list of critical low voltage transmission lines will be provided to FERC. We do not interpret Order 693 to direct NERC to provide this list. Rather, we interpret that FERC asks for defining a criteria that would include low voltage transmission lines that have impact on Bulk Power System reliability. We do not think the list is required. 2. The SAR indicates: "The standard DT may consider other criteria in determining

Question #4			
Commenter	**Yes**	**No**	**Comment**
			applicability of the standard to sub 200kV lines…" Per Order 693, the criteria is quite clearly stated to be the transmission lines of less than 200 kV that could impact Bulk Power System reliability. We don't feel any other criteria would be necessary. Further, to identify the candidates that meet these criteria, we believe they should be determined by the Reliability Coordinator, similar to the PRC-023 standard, since the RC has the primary responsibility and knowledge of interconnection reliability impact. 3. We do not understand why the SDT considers removing Category 3 incidents? In our view, Category 3 outages are important information for assessing the effectiveness of vegetation program. Since the industry started reporting vegetation related outages about 3 years ago, data collected so far indicates that of a total of 98 reported vegetation outages, 67 of them were category 3 outages. With this high percentage, reporting of Category 3 events should be a must since the associated trends can provide valuable information to the TOs to aid its evaluation of the vegetation management program. 4. The white paper and field tests are a good idea and the SDT should be commended for these, especially the white paper. 5. Item 2 under the FERC Order 693 Items in the Detailed Description Section indicates the SDT will also collection outage data. While we understand that FERC has directed the ERO to collect outage data for transmission outages of lines that cross both federal and non-federal lands, we do not feel that it is the SDT's role to perform this task. We feel that this task should be performed by the ERO line functions or a group separate from the SDT such that the task does not add burden to the SDT which may slow down the standard development process or result in the standard development being driven by unanalyzed data and resulting in erroneous requirements. 6. With respect to reporting exemptions, our position during development of the previous version of this standard was to limit them. We commend the SDT intention to clarify the outage exemptions under major disasters, but to consider including all category outage exemptions in the standard body is too prescriptive and will add to the already extended list. It can end up with a very long list of outage exemptions, thereby reducing the coverage of the standard substantially and defeating its purpose
Response: 1. On the basis of the responses from stakeholders to Question #2 above, the SAR DT's assessment is that further			

Question #4			
Commenter	**Yes**	**No**	**Comment**
specificity may be needed to aid in identifying which <200kV transmission lines should come under the purview of this standard. The SDT shall take under consideration other applicability parameter criteria, various stakeholder proposals including IROL violation potential. 2. See # 1 above. 3. The SAR indicates that the Standard Drafting Team will review reporting criteria for Category 3 outages and will review the reporting requirement of Category 3 outages in R.3 and R.4. 4. The SAR DT thanks you for your comment. 5. The SDT looks to receive the results of the ERO analysis and use it in developing the standard. 6. The SDT will review the reporting exemptions to include all category outages under major disasters in Requirement R3.2.			
IRC SRC	☑		1. The SAR indicates that a list of critical low voltage transmission lines will be provided to FERC. We do not interpret Order 693 to direct NERC to provide this list. Rather, we interpret that FERC asks for defining a criteria that would include low voltage transmission lines that have impact on Bulk Power System reliability. We do not think the list is required. 2. The SAR indicates: "The standard DT may consider other criteria in determining applicability of the standard to sub 200kV lines…" Per Order 693, the criteria is quite clearly stated to be the transmission lines of less than 200 kV that could impact Bulk Power System reliability. We don't feel any other criteria would be necessary. Further, to identify the candidates that meet this criteria, we believe they should be determined by the Reliability Coordinator, similar to the PRC-023 standard, since the RC has the primary responsibility and knowledge of interconnection reliability impact. 3. We do not understand why the SDT considers removing Category 3 incidents? In our view, Category 3 outages are important information for assessing the effectiveness of vegetation program. Since the industry started reporting vegetation related outages about 3 years ago, data collected so far indicates that of a total of 98 reported vegetation outages, 67 of them were category 3 outages. With this high percentage, reporting of Category 3 events should be a must since the associated trends can provide valuable information to the TOs to aid its evaluation of the vegetation management program. 4. The white paper and field tests are a good idea and the SDT should be commended for these, especially the white paper.

Question #4			
Commenter	Yes	No	Comment
			5. Item 2 under the FERC Order 693 Items in the Detailed Description Section indicates the SDT will also collect outage data. While we understand that FERC has directed the ERO to collect outage data for transmission outages of lines that cross both federal and non-federal lands, we do not feel that it is the SDT's role to perform this task. We feel that this task should be performed by the ERO or a group separate from the SDT such that the task does not add burden to the SDT which may slow down the standard development process or result in the standard development being driven by unanalyzed data and resulting in erroneous requirements. 6. With respect to reporting exemptions, our position during development of the previous version of this standard was to limit them. We commend the SDT intention to clarify the outage exemptions under major disasters, but to consider including all category outage exemptions in the standard body is too prescriptive and will add to the already extended list. It can end up with a very long list of outage exemptions, thereby reducing the coverage of the standard substantively and defeating its purpose. If this list was to be developed, they could be attached as guidelines aside of the standard. 7. The SAR DT states it will deal with "critical facilities" . The SRC suggest that the DT not use the word "critical" and adopt another term. There is a need to define in a single standard what the term "critical" means. Standards FAC-014 (R5.1.1); IRO-002-1 (R6) and others use the term "critical" as in: critical loads, critical infrastructure, critical assets. The Veg Management Team is asked to avoid making the current situation worse.

Response:

1. On the basis of the responses from stakeholders to Question #2 above, the SAR DT's assessment is that further specificity may be needed to aid in identifying which <200kV transmission lines should come under the purview of this standard. The SDT shall take under consideration other applicability parameter criteria, various stakeholder proposals including IROL violation potential.
2. The FERC Order includes the following language which indicates that FERC would support inclusion of any circuit below 200 kV that was subject to an IROL and the SAR has been written to allow this modification..
3. The SAR indicates that the Standard Drafting Team will review reporting criteria for Category 3 outages and will review the reporting requirement of Category 3 outages in R.3 and R.4.
4. The SDT shall consider producing a white paper to aid in clarifying the intent of the standard, however a field test is not contemplated at this time.
5. The SAR was revised to clarify that it is the ERO that will collect data and the Standard DT will receive the results of

Question #4			
Commenter	**Yes**	**No**	**Comment**
the ERO analysis and use it in developing the standard. 6. The standard DT will review the reporting exemptions to include all category outages under major disasters in Requirement R3.2. 7. The FERC Order includes the following language which indicates that FERC would support inclusion of any circuit below 200 kV that was subject to an IROL and the SAR has been written to allow this modification.			
ISO-NE	☑		1. The SAR indicates that a list of critical low voltage transmission lines will be provided to FERC. We do not interpret Order 693 to direct NERC to provide this list. Rather, we interpret that FERC asks for defining a criteria that would include low voltage transmission lines that have impact on Bulk Power System reliability. We do not think the list is required. 2. The SAR indicates: "The standard DT may consider other criteria in determining applicability of the standard to sub 200 kV lines…" Per Order 693, the criteria is quite clearly stated to be the transmission lines of less than 200 kV that could impact Bulk Power System reliability. We don't feel any other criteria would be necessary. Further, to identify the candidates that meet this criteria, we believe they should be determined by the Reliability Coordinator, similar to the PRC-023 standard, since the RC has the primary responsibility and knowledge of interconnection reliability impact. 3. We do not understand why the SDT considers removing Category 3 incidents. In our view, Category 3 outages are important information for assessing the effectiveness of a vegetation program. Since the industry started reporting vegetation-related outages about 3 years ago, data collected so far indicates that of a total of 98 reported vegetation outages, 67 of them were category 3 outages. With this high percentage, reporting of Category 3 events should be a must since the associated trends can provide valuable information to the TOs to aid its evaluation of the vegetation management program. 4. The white paper and field tests are a good idea and the SDT should be commended for these, especially the white paper. 5. Item 2 under the FERC Order 693 Items in the Detailed Description Section indicates the SDT will also collect outage data. While we understand that FERC has directed the ERO to collect outage data for transmission outages of lines that cross both federal and non-federal lands, we do not feel that it is the SDT's role to perform this task. We feel that this task should be performed by the ERO or a group separate from the SDT such

Question #4			
Commenter	**Yes**	**No**	**Comment**
			that the task does not add burden to the SDT which may slow down the standard development process or result in the standard development being driven by unanalyzed data and resulting in erroneous requirements. 6. With respect to reporting exemptions, our position during development of the previous version of this standard was to limit them. We commend the SDT's intention to clarify the outage exemptions under major disasters, but to consider including all category outage exemptions in the standard body is too prescriptive and will add to the already extended list. It can end up with a very long list of outage exemptions, thereby reducing the coverage of the standard substantively and defeating its purpose. If this list was to be developed, they could be attached as guidelines aside of the standard. 7. The SAR DT states it will deal with "critical facilities." The SRC suggest that the DT not use the word "critical" and adopt another term. There is a need to define in a single standard what the term critical means. Standards FAC-014 (R5.1.1); IRO-002-1 (R6) and others use the term "critical" as in: critical loads, critical infrastructure, critical assets. This Team is asked to avoid making the current situation worse.

Response:

1. On the basis of the responses from stakeholders to Question #2 above, the SAR DT's assessment is that further specificity may be needed to aid in identifying which <200kV transmission lines should come under the purview of this standard. The SDT shall take under consideration other applicability parameter criteria, various stakeholder proposals including IROL violation potential.
2. The FERC Order includes the following language which indicates that FERC would support inclusion of any circuit below 200 kV that was subject to an IROL and the SAR has been written to allow this modification..
3. The Standard Drafting Team intends to review reporting criteria for Category 3 outages in the proposed technical reference material and may review the reporting requirement of Category 3 outages in R.3 and R.4.
4. The SDT shall consider producing a white paper to aid in clarifying the intent of the standard, however a field test is not contemplated at this time.
5. The standard DT looks to receive the results of the ERO analysis and use it in developing the standard.
6. The standard DT will review the reporting exemptions to include all category outages under major disasters in Requirement R3.2.
7. The FERC Order includes the following language which indicates that FERC would support inclusion of any circuit below 200 kV that was subject to an IROL and the SAR has been written to allow this modification.

Question #4			
Commenter	**Yes**	**No**	**Comment**
MRO	☑		If the Regional Reliability Organization is removed as an applicable entity, what is the Regional Entity's responsible? How will a general consensus be formed? How do you get people to participate in this formation? For good planning and application of standards, methodologies need to be consistently applied through guidelines to the drafting teams. Specifically, this standard should provide consistent methodology that provides guidance to the transmission owner. In the next revision of the standard, the MRO requests that more authority be given to the applicable entities with respect to the latitude allowed them in removing trees to the legal limits of their agreement. The MRO commends FERC on empowering NERC and the SAR DT via their Order 693 to revisit the issue of clearances for lines on both Federal and non-Federal Lands. It has come to the attention of the MRO that Federal Forest Employees as well as BLM employees have begun the practice of chemically treating noxious weeds and invasive species on Federal Lands. he MRO would like to have FERC, NERC, and the Standard DT consider meeting with Federal Land Managers to discuss, on a National Level, the issue of herbicide application by utilities on Federal Lands. At the present time there are inconsistencies regionally on this issue that allow application in some regions but not in others.
Response: 1. The term RRO is no longer in use and RE (or regional entity) is now the preferred term for the former Regional Reliability Organizations. The term RE is defined in the delegation agreements between these organizations and the ERO. 2. Such a guideline exists and is available on the NERC website entitled "Standard Drafting Team Guidelines". 3. See answer #2 above. 4. The removal of trees within the limits stated in agreements is outside the scope of this standard. 5. The coordination of the use of herbicides is outside the scope of this standard.			
National Grid	☑		1) National Grid supports amending FAC-003-1 to bring the Standard into compliance with "latest version of the Reliability Standard Development Procedure and the ERO Sanctions Guidelines" as discussed in the SAR Background Information. 2) We do not support amendments to the Standard to address all of the issues raised by FERC Order 693. We believe most of the FERC's concerns can be addressed by

Question #4			
Commenter	**Yes**	**No**	**Comment**
			developing a "white paper" to better explain the Standard and guide its implementation. 3) National Grid does not support changing the basic approach to defining clearance from vegetation. The clearance 1 and clearance 2 concept adopts the two management approaches used by most TO's today and required in some state or ISO level standards. National Grid supports using the reference to IEEE 516 as the basis for clearance 2 for two reasons: 1 - there is no other definitive reference for flash over distances to vegetation and 2- decades of experience by TO's acrosss the North America suggest the IEEE 516 distances are more than adequate. The well known tree caused outages in 1996 and 2003 occurred as a result of hard contact with vegetation not flashover at distances close to those in IEEE 516. Furthermore, FERC accepted IEEE 516 as appropriate for use in vegetation management in the October 2006, NOPR. 4) National Grid supports amending the definition of a right-of-way though we are not clear on what is meant in the SAR language by "to encompass required clearing areas". National Grid is concerned with the interpretation of the present definition that the right-of-way includes uncleared fee owned or easement land reserved for future construction. In many jurisdictions the TO may not be allowed to remove trees from these areas. A "white paper" could better describe the definition and prevent future compliance issues stemming from an ambiguous definition.
Response: 1. The SAR DT thanks you for your comment. 2. The SAR indicates that the SDT will produce a technical white paper to clarify intent of the standard. 3. The SAR DT agrees with the commenter not to change the basic approach and recognizes that sections of IEEE 516 standard pertaining to minimum air insulation distances are applicable in determining minimum vegetation clearances to prevent flashovers. 4. The Standard DT will review the definition of ROW. See also answer #2 above.			
Northeast Utilities	☑		NU does not support the proposed revisions based on the issues raised by FERC Order 693. The Standard has not been in effect long enough to determine if there are any shortcomings with the current requirements. It is our position that the current clearance requirements are satisfactory in that a base minimum distance as provided under IEEE Section 516 is sufficient and there is the need for variations in the second level of clearances base on Regional needs and conditions. The revisions to the definition of "right-of-way" to encompass required clearance areas can e problematic as this could cause significant problems with current systems. There is no detailed description on what the new definition will include or what the actual impact will be to TO's. If the definition will include defined limits or widths of rights-of-

Question #4			
Commenter	**Yes**	**No**	**Comment**
			way this may affect current facilities that do not meet these distances. Second, there are areas where the company owns or possesses additional area beyond the current maintained right-of-way widths. Is it proposed that the new definition expand the limits of clearing or maintenance to include easemented or fee-owned areas beyond the current maintained limits? Until the new definition can be presented - it is difficult to support any changes at this time and we can only comment on the perceived negative impacts.
Response: The SDT will review the standard to address the Commission's determinations. The standard DT will review the definition of ROW. Note that the ERO is required to respond to the FERC directives.			
NYISO	☑		1. The SAR indicates that a list of critical low voltage transmission lines will be provided to FERC. We do not interpret Order 693 to direct NERC to provide this list. Rather, we interpret that FERC asks for defining a criteria that would include low voltage transmission lines that have impact on Bulk Power System reliability. We do not think the list is required. 2. The SAR indicates: "The standard DT may consider other criteria in determining applicability of the standard to sub 200kV lines…" Per Order 693, the criteria is quite clearly stated to be the transmission lines of less than 200 kV that could impact Bulk Power System reliability. We don't feel any other criteria would be necessary. Further, to identify the candidates that meet this criteria, we believe they should be determined by the Reliability Coordinator, similar to the PRC-023 standard, since the RC has the primary responsibility and knowledge of interconnection reliability impact. 3. We do not understand why the SDT considers removing Category 3 incidents? In our view, Category 3 outages are important information for assessing the effectiveness of vegetation program. Since the industry started reporting vegetation related outages about 3 years ago, data collected so far indicates that of a total of 98 reported vegetation outages, 67 of them were category 3 outages. With this high percentage, reporting of Category 3 events should be a must since the associated trends can provide valuable information to the TOs to aid its evaluation of the vegetation management program. 4. The white paper and field tests are a good idea and the SDT should be commended for these, especially the white paper. 5. Item 2 under the FERC Order 693 Items in the Detailed Description Section indicates

<table>
<tr><th colspan="4">Question #4</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td>the SDT will also collect outage data. While we understand that FERC has directed the ERO to collect outage data for transmission outages of lines that cross both federal and non-federal lands, we do not feel that it is the SDT's role to perform this task. We feel that this task should be performed by the ERO or a group separate from the SDT such that the task does not add burden to the SDT which may slow down the standard development process or result in the standard development being driven by unanalyzed data and resulting in erroneous requirements.

6. With respect to reporting exemptions, our position during development of the previous version of this standard was to limit them. We commend the SDT intention to clarify the outage exemptions under major disasters, but to consider including all category outage exemptions in the standard body is too prescriptive and will add to the already extended list. It can end up with a very long list of outage exemptions, thereby reducing the coverage of the standard substantively and defeating its purpose. If this list was to be developed, they could be attached as guidelines aside of the standard.</td></tr>
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2. The FERC Order includes the following language which indicates that FERC would support inclusion of any circuit below 200 kV that was subject to an IROL and the SAR has been written to allow this modification..
3. The Standard Drafting Team intends to review reporting criteria for Category 3 outages in the proposed technical reference material and may review the reporting requirement of Category 3 outages in R.3 and R.4.
4. The SAR indicates that the SDT will produce a white paper to aid in clarifying the intent of the standard, however a field test is not contemplated at this time.
5. The SDT looks to receive the results of the ERO analysis and use it in developing the standard.
6. The SDT will review the reporting exemptions to include all category outages under major disasters in Requirement R3.2.</td></tr>
<tr><td>PGE</td><td>☑</td><td></td><td>1) Applicability 4.3 of the standard - PG&E believes the RE is in the best position to determine sub-200kV facilities are designated critical and covered under FAC-003-1. We suggest the ERO direct the RE to provide a list of sub-200kV lines designated critical along with methodology used to make that determination.

2) Clearances for lines on federal and non-federal lands - PG&E believes there should be no distinction between requirements on different lands. Vegetation encroachments have</td></tr>
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Question #4			
Commenter	**Yes**	**No**	**Comment**
			the same impact regardless of land ownership. 3) Definition of right of way - agreed 4) Suitability of IEEE 516-2003 - PG&E believes the use of IEEE 516 as the standard for clearance requirements are adequate to ensure transmission system reliability provided the TO has an appropriate methodology for determining clearance at time of trim and an adequate cycle to prevent vegetation from encroaching within minimum distances. Use of ANSI Z133.3 or FedOSHA 1910, as suggested by FERC, is not appropriate as it is intended for worker safety and not system reliability. TO compliance with R1.2 of the standard should address concerns FERC has with maintaining minimum clearance. 5-7) Procedural items - No comment 8) Preparation of technical manual (white paper) - agreed 9) PG&E believes the current reporting requirements under R3 of the standard should be revised. Distinction is placed on fall-in's "in and out of the ROW" and may not be the best method for determining severity for reporting purposes. PG&E believes a better distinction is (a) green/healthy/no obvious decline and (b) dead or obvious signs of disease, decay or decline. A key component of any TMVP should be hazard tree mitigation regardless if in or out of the ROW. Suggested categories: Category 1 - Any grow-in (as currently stated). Category 2 - Any fall-in of a dead tree or one with obvious signs of disease, decay or decline in or out of the ROW. Category 3 - Either eliminate this category or specify healthy green tree or tree with no obvious signs of decline (if retained, be specific about this being for reporting purposes only) PG&E recognizes that tree failures, even if dead or diseased, are not necessarily an indicator of problematic VM program and the severity level should be reflected as such. Tree density along with other factors make 100% identification not possible. However, multiple occurrences could be an indicator of substandard performance and the current standard does remains silent in respect to hazard trees other than if in or out of the ROW.
Response:			

Question #4			
Commenter	Yes	No	Comment
1. On the basis of the responses from stakeholders to Question #2 above, the SAR DT's assessment is that further specificity may be needed to aid in identifying which <200kV transmission lines should come under the purview of this standard. The SDT shall take under consideration other applicability parameter criteria, various stakeholder proposals including IROL violation potential.. 2. The SAR DT concurs with the commenter with respect to applying this standard to Federal and non-Federal lands. The standard DT will evaluate the suitability of a case-by-case approach. 3. The standard DT will review the definition of ROW. 4. The SAR DT agrees with the commenter and recognizes that sections of IEEE 516 standard pertaining to minimum air insulation distances are applicable in determining minimum vegetation clearances to prevent flashovers. 5. n/a 6. n/a 7. n/a 8. The SAR indicates that the SDT will produce a technical white paper to clarify intent of the standard. 9. The SAR indicates that the SDT will review reporting criteria for Category 3 outages and will review the reporting requirement of Category 3 outages in R.3 and R.4. The SDT and Compliance Elements DT will review and assign Violation Severity Levels when modifying FAC-003-1.			
PGN	☑		Progress Energy Carolinas (PEC) and Progress Energy Florida (PEF) do not agree that each of 11 items listed in the SAR are necessary to improve reliability. The following comments are offered for each of the 11 items identified in the SAR detail description: 1. Standard Applicability: PEC and PEF believe that the current standard wording for determining facilities subject to this standard should not be revised. The standard as it is written provides for lines below 200kV, that are determined to impact the grid, to be subject to the standard. Extending the requirements to a bright line below 200kV, such as 100kV, will dilute the focus on those lines that impact grid reliability, lines >200kV, and shift attention to facilities, those <200kV, that do not necessarily impact grid reliability. Customer reliability is an issue that impacts customer satisfaction and is generally driven by state utility commissions. While some facilities above 200kV directly support customer load, transmission lines below 200kV primarily support customer load, and interruptions to those facilities generally reduce load on the grid. The majority of transmission facilities below 200 kV also have significantly different design/construction/operating characteristics and have not been cited as impacting bulk

Question #4			
Commenter	**Yes**	**No**	**Comment**
			power system reliability. For example, the Final Report on the August 14, 2003 Blackout in the United states and Canada: Causes and Recommendations April 2004 by the U.S.-Canada Power System Outage Task Force and all referenced major blackouts (pages 103-115) in that report, cited only outages which involved vegetation at line voltages above 200kV. Generally applying requirements that are appropriate for >200kV lines to lines less than 200kV will result in significant documentation and reporting of items such as restrictions, mitigation plans, off right-of-way vegetation-related outage investigation/ information and other issues, all of which dilutes the focus on lines that directly impact bulk power system reliability. Revising the standard to use general criteria or broad language for defining "Bulk Power System" transmission lines covered by the standard is a "one size fits all" approach. If that approach were taken, the standard would cover a significant number of transmission lines that have no direct impact on bulk power system reliability under standard planning/operating conditions, resulting in a significant cost burden for electric customers without improving "grid" reliability. PEC and PEF believe that the applicability provision of the standard should instead focus attention of the standard only on the transmission lines below 200kV that directly impact "Bulk Power System" reliability, as the current version requires. While PEC and PEF recognize some validity in the Commission's concern, PEC and PEF recommend that the applicability provision of this standard should be revised only if existing system design, planning or operating reliability criteria and parameters are considered as a basis for defining the applicability of the standard. To that end, PEC and PEF recommend each Regional Entity (RE) determine applicability of FAC-003 to those lines within the region that are between 100kV and 200KV, if, and only if, they are identified as operationally significant elements of Interconnection Reliability Operating Limits ("IROLs"). That is, any facility below 200kV that, by itself, would cause an Interconnected Reliability Limit Violation should the facility be outaged. 2. Issue of Clearances (Federal vs Non-Federal Lands): FAC-003-1 presently requires the transmission owner (TO) "identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on

Question #4			
Commenter	**Yes**	**No**	**Comment**
			conductor sway." The intent of this requirement is to ensure adequate clearances to prevent vegetation related outages. PEC and PEF believe that only the TO has the technical information required to determine the clearances that are necessary at the time of VM work and that any "federal lands exemption" to clearances will result in inadequate clearances for the existing conditions. Consistency in application of the TO's clearance requirements, not exceptions, is the only assurance in providing a uniform and reliable electrical system to meet the nation's current and future energy demands. Any exception for a case by case clearance approach to determine vegetation management activities/clearances on Federal lands will continue to drive inconsistency and/or delays associated with TO vegetation management decisions being driven by diverse vegetation management practices/beliefs and staff changes at the local level of Federal agencies. Vegetation-related outages have occurred on Federal lands as a result of this case by case approach, and if "Bulk Power Transmission System" lines continue to be addressed on a "case by case" basis on National Forest Service (or any other Federal lands), those lines will potentially be subject to a higher risk for vegetation-related outages, resulting in reduced reliability for the "Bulk Power System". PEC and PEF believe that reliability of the "Bulk Power System" should have the same focus on Federal and private lands and that the EEI MOU with federal agencies is an appropriate avenue for TO's to identify clearances on Federal lands, not an exemption in the language of a reliability standard. 3. Defining Right-of-Way: PEC and PEF agree that it is appropriate to further address the definition of "right-of-way". Corridor widths that exceed the design clearance requirements have been acquired for a variety of reasons in the past; future use, property line buffers, etc. Vegetation in those areas that would normally be outside of the corridor width necessary for reliable operation of the facility, but within an expanded easement area, should not be considered, or treated, different than vegetation that is outside of a defined easement/permit right-of-way corridor that was designed and acquired specifically for the reliable operation of a single line. 4. IEEE Standard for Minimum Clearances:

Question #4			
Commenter	Yes	No	Comment
			PEC and PEF believe that the IEEE 516-2003 tables are appropriate for defining the minimum acceptable clearances to prevent flashover between conductors and vegetation under all rated electrical operating conditions. Closer minimum clearances such as the minimum length of a support insulator could have been adopted as a "lowest common denominator" clearance. However the clearance in IEEE 516-2003 was adopted to ensure an additional margin of reliability. FERC staff has made references to the use of ANSI Z-133 which is a safety standard that addresses worker safety as well as the safety of the general public. The purpose of ANSI Z-133 is to address worker safety and is not focused on transmission line reliability, which is the purpose of FAC-003-1. OSHA, NESC and other related safety standards have clearances in excess of IEEE 516-2003. Those clearances are clearly focused on safety issues and will still apply to other aspects of design and operation of electric facilities (such as public and worker safety) but are not appropriate to be referenced in a vegetation management reliability standard as a flashover clearance. 5/6/7. Procedural Items: PEC and PEF agree that the procedural items related to formatting RRO references and revising the compliance elements to meet the new standard format should be addressed by the standard drafting team. 8. Technical Reference Materials: PEC and PEF agree that a "white paper" that defines the technical basis for the standard is appropriate. This type of document, if crafted by the drafting team, should help to avoid the potential for differences in interpretation of the standard's requirements by the various regions during the audit process. 9. Category 3 Outages: Since control off right-of-way vegetation is generally beyond control of the TO and since "fall-in" outages are random events that do not threaten grid reliability, PEC and PEF believe that the reporting of category 3 outages should be removed from the requirements. 10. Requirement R4:

Question #4			
Commenter	**Yes**	**No**	**Comment**
			PEC and PEF believe that requirement R4 should be deleted from the standard, since the ERO formation provides for delegation of authority to the regional entities. 11. Reporting Exemptions: PEC and PEF believe that the reporting requirement exemptions for natural disasters should include all categories of outages. For example, with outages caused by high winds, hurricanes, tornadoes, etc., it would be difficult (or practically impossible in some cases) to determine if the vegetation came from on, or off, the "right-of-way". In addition, the effort and time necessary to make that determination would result in delaying outage restoration efforts.
Response: 1. On the basis of the responses from stakeholders to Question #2 above, the SAR DT's assessment is that further specificity may be needed to aid in identifying which <200kV transmission lines should come under the purview of this standard. The SDT shall take under consideration other applicability parameter criteria, various stakeholder proposals including IROL violation potential.. 2. The SAR DT concurs with the commenter with respect to applying this standard to Federal and non-Federal lands. The standard DT will evaluate the suitability of a case-by-case approach. 3. The standard DT will review the definition of ROW. 4. The SAR DT agrees with the commenter and recognizes that sections of IEEE 516 standard pertaining to minimum air insulation distances are applicable in determining minimum vegetation clearances to prevent flashovers. 5. NERC standards must be updated to comply with new procedural requirements and must include compliance elements. 6. See #5 7. See #5 8. The SAR indicates that the SDT will produce a technical white paper to clarify intent of the standard. 9. The SAR indicates that the SDT will review reporting criteria for Category 3 outages and will review the reporting requirement of Category 3 outages in R.3 and R.4. 10. The standard DT will consider deletion of R.4. 11. The standard DT will review the reporting exemptions to include all category outages under major disasters in Requirement R3.2.			
SERC VMS	☑		The SERC VMS does not agree that each of 11 items listed in the SAR are necessary to improve reliability. The following comments are offered for each of the 11 items identified in the SAR detail description: 1. Standard Applicability:

Question #4			
Commenter	**Yes**	**No**	**Comment**
			The SERC VMS disagrees with revising the 200 kV threshold for determining facilities subject to this standard. Extending the requirements to lines other than those >200kV will dilute the focus on those lines that impact grid reliability and shift attention to facilities, those <200kV. The reliability of lower voltage lines involves local customers' reliability and satisfaction hence that reliability should be addressed by local and state utility commissions. The majority of the >200kV lines are solely elements of the grid and and interruptions to those lines negatively impact grid reliability. The majority of the <200kV lines primarily support customer load, and interruptions to those facilities actually reduces load on the grid. The majority of transmission facilities below 200 kV also have significantly different design/construction/operating characteristics and have not been cited as impacting bulk power system reliability. For example, the Final Report on the August 14, 2003 Blackout in the United states and Canada: Causes and Recommendations April 2004 by the U.S.-Canada Power System Outage Task Force and all referenced major blackouts (pages 103-115) in that report, cited only outages which involved vegetation at line voltages above 200kV. Generally applying requirements that are appropriate for >200kV lines to lines less than 200kV will result in significant documentation and reporting of items such as restrictions, mitigation plans, off right-of-way vegetation-related outage investigation/ information and other issues, all of which dilutes the focus on lines that directly impact bulk power system reliability. Revising the standard to use general criteria or broad language for defining "Bulk Power System" transmission lines covered by the standard is a “one size fits all” approach. If that approach were taken, the standard would cover a significant number of transmission lines that have no direct impact on bulk power system reliability under standard planning/operating conditions, resulting in a significant cost burden for electric customers without improving “grid” reliability. The SERC VMS believes that the applicability provision of the standard should instead focus attention of the standard only on the transmission lines below 200kV that directly impact “Bulk Power System” reliability, as the current version requires. In sum, while the SERC VMS recognizes some validity in the Commission’s concern, the SERC VMS recommends that the applicability provision of this standard should be revised only if existing system design, planning or operating reliability criteria and parameters

Question #4			
Commenter	**Yes**	**No**	**Comment**
			are considered as a basis for defining the applicability of the standard. To that end, the SERC VMS recommends each Regional Entity (RE) determine applicability of FAC-003 to those lines within the region that are between 100kV and 200KV, if, and only if, they are identified as operationally significant elements of Interconnection Reliability Operating Limits ("IROLs"). That is, any facility below 200kV that by itself would cause an Interconnected Reliability Limit Violation should the facility be outaged. 2. Issue of Clearances (Federal vs Non-Federal Lands): FAC-003-1 presently requires the transmission owner (TO) "identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway." The intent of this requirement is to ensure adequate clearances to prevent vegetation related outages. The SERC VMS believes that only the TO has the technical information required to determine the clearances that are necessary at the time of VM work and that any "federal lands exemption" to clearances will result in inadequate clearances for the existing conditions. Consistency in application of the TO's clearance requirements, not exceptions, is the only assurance in providing a uniform and reliable electrical system to meet the nation's current and future energy demands. Any exception for a case by case clearance approach to determine vegetation management activities/clearances on Federal lands will continue to drive inconsistency and/or delays associated with TO vegetation management decisions being driven by diverse vegetation management practices/beliefs and staff changes at the local level of Federal agencies. Vegetation-related outages have occurred on Federal lands as a result of this case by case approach, and if "Bulk Power Transmission System" lines continue to be addressed on a "case by case" basis on National Forest Service (or any other Federal lands), those lines will potentially be subject to a higher risk for vegetation-related outages, resulting in reduced reliability for the "Bulk Power System". The SERC VMS believes that reliability of the "Bulk Power System" should have the same focus on Federal and private lands and that the EEI MOU with federal agencies is the appropriate vehicle for TO's to identify clearance variances on Ferderal lands, not exemption language in the standard.

Question #4			
Commenter	**Yes**	**No**	**Comment**
			3. Defining Right-of-Way: The SERC VMS agrees that it is appropriate to further address the definition of "right-of-way". Corridor widths beyond design clearance requirements have been acquired for a variety of reasons in the past; future use, property line buffers, etc. Vegetation in those areas that would normally fall outside of the area necessary for operation of the facility should not be considered or treated different than vegetation that is outside of a defined easement/permit area that is designed for the reliable operation of an existing single line corridor. 4. IEEE Standard for Minimum Clearances: The SERC VMS disagrees with objections to the use of the IEEE 516-2003 clearance as the minimum acceptable distances for "Clearance 2". The IEEE 516-2003 tables are appropriate for defining the minimum acceptable clearances to prevent flashover between conductors and vegetation under all rated electrical operating conditions. Closer minimum clearances such as the minimum length of a support insulator could have been adopted as a "lowest common denominator" clearance. However the clearance in IEEE 516-2003 was adopted to ensure an additional margin of reliability. FERC staff references ANSI Z-133 which is a safety standard that addresses worker safety as well as the safety of the general public. As such, the purpose of ANSI Z-133 is to address worker safety and is not focused on transmission line reliability, which is the purpose of FAC-003-1. OSHA, NESC and other related safety standards have clearances in excess of IEEE 516-2003. Those clearances are clearly focused on safety issues and will still apply to other aspects of design and operation of electric facilities (such as public and worker safety) but are not appropriate to be referenced in a vegetation management reliability standard. 5/6/7. Procedural Items: The SERC VMS agrees that the procedural items related to formatting RRO references and additional compliance elements should be addressed by the standard drafting team. 8. Technical Reference Materials: The SERC VMS agrees that a "white paper" that defines the technical basis for the

Question #4			
Commenter	**Yes**	**No**	**Comment**
			standard is appropriate to avoid the potential for differences in interpretation of the standard's requirements during the various region's audit processes. 9. Category 3 Outages: Since the right to control off right-of-way vegetation is generally beyond control of the TO, the SERC VMS believes that the reporting of category 3 outages should be removed from the requirements. 10. Requirement R4: The SERC VMS believes that requirement R4 should be deleted from the standard, based on the ERO formation and the process for delegation of authority to the regional entities. 11. Reporting Exemptions: The SERC VMS believes that the reporting requirement exemptions for natural disasters should include all categories of outages. It would, for example, be difficult, without delaying restoration efforts, to determine if the vegetation from high winds, hurricanes, tornadoes, etc. is from on or off the "right-of-way".

Response:

1. On the basis of the responses from stakeholders to Question #2 above, the SAR DT's assessment is that further specificity may be needed to aid in identifying which <200kV transmission lines should come under the purview of this standard. The SDT shall take under consideration other applicability parameter criteria, various stakeholder proposals including IROL violation potential..
2. The SAR DT concurs with the commenter with respect to applying this standard to Federal and non-Federal lands. The standard DT will evaluate the suitability of a case-by-case approach.
3. The standard DT will review the definition of ROW.
4. The SAR DT agrees with the commenter and recognizes that sections of IEEE 516 standard pertaining to minimum air insulation distances are applicable in determining minimum vegetation clearances to prevent flashovers.
5. NERC standards must be updated to comply with new procedural requirements and must include compliance elements.
6. See #5
7. See #5
8. The SAR indicates that the SDT will produce a technical white paper to clarify intent of the standard.
9. The SAR indicates that the SDT will review reporting criteria for Category 3 outages and will review the reporting requirement of Category 3 outages in R.3 and R.4.

Question #4			
Commenter	**Yes**	**No**	**Comment**
10. The standard DT will consider deletion of R.4. 11. The standard DT will review the reporting exemptions to include all category outages under major disasters in Requirement R3.2.			
TVA	☑		We feel that the reporting of Category 3 outages should be eliminated. We agree with the need for a "white paper" to expand on definitions and intent. We feel that a defined maintainable width of right of way is more appropriate than the actual easement widths because easement widhts are not purchased or operated exclusively with or for vegetation manitenance activies. We will be pleased to share greater details on this concern if requested.
Response: The SAR DT thanks you for your comments.			
VELCO		☑	

Standard Authorization Request Form

Revisions to FAC-003-1 Transmission Vegetation Management Program Project 2007-07	
Request Date	January 9, 2007
Revised Date	April 2, 2007

SAR Requestor Information	**SAR Type** (*Check a box for each one that applies.*)	
Name Richard Dearman	☐	New Standard
Primary Contact Richard Dearman	☒	Revision to existing Standard
Telephone (256) 851-3523 Fax	☐	Withdrawal of existing Standard
E-mail redearman@tva.gov	☐	Urgent Action

Purpose / Industry Need (Describe the purpose of the standard — what the standard will achieve in support of reliability.)

The purpose of revising this standard is to:

1. Provide an adequate level of reliability for the North American electric transmission system – by verifying that the standard is complete and that its requirements are set at an appropriate level to ensure reliability.
2. Incorporate other general improvements described in the attached Standard Review Guidelines to bring it into conformance with the latest version of the Reliability Standard Development Procedure and the ERO Sanctions Guidelines.
3. Consider comments received from ERO regulatory authorities and stakeholders, as noted in the attached review sheets.
4. Satisfy the standards procedure requirement for five-year review of the standards.

Detailed Description

This is a new standard that was approved in 2006. It has some 'fill-in-the-blank' components to eliminate. In addition, the following comments submitted by FERC and stakeholders need to be addressed in the refinement of the standard:

FERC Order 693 items

1. To address the issue regarding applicability:
   - The Standard DT shall work with the reliability entities and the ERO to collect and make available to the FERC, a list of critical lower voltage transmission lines. (Refer to Applicability 4.3 section of the standard.)
     - The standard DT may consider other criteria in determining applicability of the standard to sub 200kV lines.
2. To address the issue of clearances for lines on both federal and non-federal lands:
   - The standard drafting team shall collect and analyze outage data then consider defining clearances needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal and non-federal land.
3. To consider revising the definition of right of way to encompass required clearance areas.
4. To review the suitability of IEEE 516-2003 standard for minimum vegetation clearance.

Procedural items

5. Re-format standard to bring it into conformance with the latest version of the Reliability Standard Development Procedure and the ERO Sanctions Guidelines.
6. Remove references to RRO in the standard and substitute a responsible entity.
7. Add compliance elements such as time horizons, and violation severity levels.

Stakeholder items

8. The Standard DT shall prepare technical reference material such as a "white paper" to aid in understanding the technical basis for the standard.
9. The Standard DT shall review reporting criteria for Category 3 outages in the proposed technical reference material and may remove the reporting requirement of Category 3 outages in R.3 and R.4.
10. The Standard DT shall consider deleting requirement R.4.
11. The Standard DT will review the reporting exemptions to include all category outages under major disasters in Requirement R3.2.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced Interchange Schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area..
☐	Resource Planner	Develops a (>one year) plan for the resource adequacy of specific loads within a Planning Coordinator Area.
☐	Transmission Planner	Develops a (>one year) plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator Area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and all necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission (and related reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☐	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all the following Market Interface Principles? *(Select "yes" or "no" from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Regional Differences

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Standard Review Guidelines

Applicability

Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose

Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements

Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability

Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations

Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness

Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance

In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?

Clear Language

Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality

Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements
In general, requirements for entities to have ‘capabilities’ (this would include facilities for communication, agreements with other entities, etc.) should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to ‘maintain’ their capabilities.

Consistent Terminology

To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a ‘unique’ definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the ‘verb list’ from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature;

or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Time Horizon

The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- Long-term Planning — a planning horizon of one year or longer.
- Operations Planning — operating and resource plans from day-ahead up to and including seasonal.
- Same-day Operations — routine actions required within the timeframe of a day, but not real-time.
- Real-time Operations — actions required within one hour or less to preserve the reliability of the bulk electric system.
- Operations Assessment — follow-up evaluations and reporting of real time operations.

Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. (‘Violation severity levels’ replace existing ‘levels of non-compliance.’) The violation severity levels may be applied for each requirement or combined to cover multiple requirements, as long as it is clear which requirements are included.

The violation severity levels should be based on the following definitions:

- Lower: mostly compliant with minor exceptions — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
- Moderate: mostly compliant with significant exceptions — The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.
- High: marginal performance or results — The responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.
- Severe: poor performance or results — The responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

Compliance Monitor

Replace, 'Regional Reliability Organization' with 'Regional Entity'.

Fill-in-the-blank Requirements

Do not include any 'fill-in-the-blank' requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization

Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates

Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan.

Associated Documents

If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, 'Associated Documents'.

Functional Model Version 3

Review the requirements against the latest descriptions of the responsibilities and tasks assigned to functional entities as provided in pages 13 through 53 of the draft Functional Model Version 3.

Standard Authorization Request Form

Revisions to FAC-003-1 Transmission Vegetation Management Program Project 2007-07	
Request Date	January 9, 2007
Revised Date	April 2, 2007
Revised Date	June 22, 2007

SAR Requestor Information	**SAR Type** (*Check a box for each one that applies.*)	
Name Richard Dearman	☐	New Standard
Primary Contact Richard Dearman	☒	Revision to existing Standard
Telephone (256) 851-3523 Fax	☐	Withdrawal of existing Standard
E-mail redearman@tva.gov	☐	Urgent Action

Purpose / Industry Need (Describe the purpose of the standard — what the standard will achieve in support of reliability.)

The purpose of revising this standard is to:

1. Provide an adequate level of reliability for the North American electric transmission system – by verifying that the standard is complete and that its requirements are set at an appropriate level to ensure reliability.
2. Incorporate other general improvements described in the attached Standard Review Guidelines to bring it into conformance with the latest version of the Reliability Standard Development Procedure and the ERO Sanctions Guidelines.
3. Consider comments received from ERO regulatory authorities and stakeholders, as noted in the attached review sheets.
4. Satisfy the standards procedure requirement for five-year review of the standards.

Detailed Description

This is a new standard that was approved in 2006. It has some 'fill-in-the-blank' components to eliminate. In addition, the following comments submitted by FERC and stakeholders need to be addressed in the refinement of the standard:

FERC Order 693 items

1. To address the issue regarding applicability:
   - The Standard DT shall work with the reliability entities and the ERO to collect and make available to the FERC, a list of critical lower voltage transmission lines. (Refer to Applicability 4.3 section of the standard.)
     - The standard DT may consider other criteria in determining applicability of the standard to sub 200kV lines.
2. To address the issue of clearances for lines on both federal and non-federal lands:
   - The standard drafting team shall review and analyze outage data (collected by the ERO) then consider defining clearances needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal and non-federal land.
3. To consider revising the definition of right of way to encompass required clearance areas.
4. To review the suitability of IEEE 516-2003 standard for minimum vegetation clearance.

Procedural items

5. Re-format standard to bring it into conformance with the latest version of the Reliability Standard Development Procedure and the ERO Sanctions Guidelines.
6. Remove references to RRO in the standard and substitute a responsible entity.
7. Add newly developed compliance elements such as time horizons, violation risk factors, violation severity levels, etc.

Stakeholder items

8. The Standard DT shall prepare technical reference material such as a "white paper" to aid in understanding the technical basis for the standard.
9. The Standard DT shall review reporting criteria for Category 3 outages in the proposed technical reference material and may remove the reporting requirement of Category 3 outages in R.3 and R.4.
10. The Standard DT shall consider deleting requirement R.4.
11. The Standard DT will review the reporting exemptions to include all category outages under major disasters in Requirement R3.2.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced Interchange Schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area..
☐	Resource Planner	Develops a (>one year) plan for the resource adequacy of specific loads within a Planning Coordinator Area.
☐	Transmission Planner	Develops a (>one year) plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator Area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and all necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission (and related reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☐	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☒	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all the following Market Interface Principles? *(Select "yes" or "no" from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Regional Differences

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Standard Review Guidelines

Applicability
Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose
Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements
Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability
Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations
Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness
Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance
In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?

Clear Language
Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality
Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements
In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.) should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.

Consistent Terminology
To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. A requirement that is administrative in nature;

or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

Time Horizon

The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **Long-term Planning —** a planning horizon of one year or longer.
- **Operations Planning —** operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations —** actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment —** follow-up evaluations and reporting of real time operations.

Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. ('Violation severity levels' replace existing 'levels of non-compliance.') The violation severity levels may be applied for each requirement or combined to cover multiple requirements, as long as it is clear which requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions —** The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
- **Moderate: mostly compliant with significant exceptions —** The responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.
- **High: marginal performance or results —** The responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.
- **Severe: poor performance or results —** The responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

Compliance Monitor

Replace, 'Regional Reliability Organization' with 'Regional Entity'.

Fill-in-the-blank Requirements

Do not include any 'fill-in-the-blank' requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization

Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates

Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan.

Associated Documents

If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, ‘Associated Documents’.

Functional Model Version 3

Review the requirements against the latest descriptions of the responsibilities and tasks assigned to functional entities as provided in pages 13 through 53 of the draft Functional Model Version 3.

Standard Authorization Request Form

Revisions to FAC-003-1 Transmission Vegetation Management Program Project 2007-07	
Request Date	January 9, 2007
Revised Date	April 2, 2007
Revised Date	June 22, 2007

SAR Requestor Information	**SAR Type** (*Check a box for each one that applies.*)	
Name Richard Dearman	☐	New Standard
Primary Contact Richard Dearman	☒	Revision to existing Standard
Telephone (256) 851-3523 Fax	☐	Withdrawal of existing Standard
E-mail redearman@tva.gov	☐	Urgent Action

Purpose / Industry Need (Describe the purpose of the standard — what the standard will achieve in support of reliability.)

The purpose of revising this standard is to:

1. Provide an adequate level of reliability for the North American electric transmission system – by verifying that the standard is complete and that its requirements are set at an appropriate level to ensure reliability.
2. Incorporate other general improvements described in the attached Standard Review Guidelines to bring it into conformance with the latest version of the Reliability Standard Development Procedure and the ERO Sanctions Guidelines.
3. Consider comments received from ERO regulatory authorities and stakeholders, as noted in the attached review sheets.
4. Satisfy the standards procedure requirement for five-year review of the standards.

Detailed Description

This is a new standard that was approved in 2006. It has some 'fill-in-the-blank' components to eliminate. In addition, the following comments submitted by FERC and stakeholders need to be addressed in the refinement of the standard:

FERC Order 693 items

1. To address the issue regarding applicability:
   - The Standard DT shall work with the reliability entities and the ERO to collect and make available to the FERC, a list of critical lower voltage transmission lines. (Refer to Applicability 4.3 section of the standard.)
     - The standard DT may consider other criteria in determining applicability of the standard to sub 200kV lines.
2. To address the issue of clearances for lines on both federal and non-federal lands:
     - The standard drafting team shall ~~collect~~ review and analyze outage data (collected by the ERO) then consider defining clearances needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal and non-federal land.
3. To consider revising the definition of right of way to encompass required clearance areas.
4. To review the suitability of IEEE 516-2003 standard for minimum vegetation clearance.

Procedural items

5. Re-format standard to bring it into conformance with the latest version of the Reliability Standard Development Procedure and the ERO Sanctions Guidelines.
6. Remove references to RRO in the standard and substitute a responsible entity.
7. Add newly developed compliance elements such as time horizons, violation risk factors, violation severity levels, etc.

Stakeholder items

8. The Standard DT shall prepare technical reference material such as a "white paper" to aid in understanding the technical basis for the standard.
9. The Standard DT shall review reporting criteria for Category 3 outages in the proposed technical reference material and may remove the reporting requirement of Category 3 outages in R.3 and R.4.
10. The Standard DT shall consider deleting requirement R.4.
11. The Standard DT will review the reporting exemptions to include all category outages under major disasters in Requirement R3.2.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports interconnection frequency in real time.
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Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
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Does the proposed Standard comply with all the following Market Interface Principles? *(Select "yes" or "no" from the drop-down box.)*
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Standard No.	**Explanation**

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SAR ID	**Explanation**

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Are the verbs on the ‘verb list’ from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

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Compliance Monitor
Replace, ‘Regional Reliability Organization’ with ‘Regional Entity’.

Fill-in-the-blank Requirements
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Effective Dates
Must be 1^{st} day of 1^{st} quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan.

Associated Documents
If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, ‘Associated Documents’.

Functional Model Version 3
Review the requirements against the latest descriptions of the responsibilities and tasks assigned to functional entities as provided in pages 13 through 53 of the draft Functional Model Version 3.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Nomination Form —Transmission Vegetation Management Standard Drafting Team

Please return this form to sarcomm@nerc.net by **July 17, 2007** with “Trans Veg SDT Nomination” in the subject line. For questions, please contact Harry Tom at 609-452-8060 or Harry.Tom@nerc.net.

Although the meeting location hasn’t been determined, the first meeting of the standard drafting team will be August 28–30, 2007.

Name:	
Organization:	
Address:	
Office Telephone:	
E-mail:	

Please briefly describe your experience and qualifications to serve on the Transmission Vegetation Management Standard Drafting Team. Candidates should have expertise in one or more of the following areas:

- **Transmission line rights-of-way (ROW) vegetation management or ROW maintenance**
- **Transmission line design and ratings**
- **Regulatory or legal considerations in ROW maintenance**
- **Existing codes and good practices in vegetation management**

Previous experience developing or applying NERC or IEEE standards is beneficial, but not a requirement.

I represent the following NERC Reliability Region(s) (check all that apply):	I represent the following Industry Segment (check one):	
☐ ERCOT	☐	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs and ISOs
☐ MRO	☐	3 — Load-serving Entities
☐ NPCC	☐	4 — Transmission-dependent Utilities
☐ RFC	☐	5 — Electric Generators
☐ SERC	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ SPP	☐	7 — Large Electricity End Users
☐ WECC	☐	8 — Small Electricity End Users
☐ NA – Not Applicable	☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
	☐	10 – Regional Reliability Organizations and Regional Entities

Which of the following Function(s) do you have expertise or responsibilities:	
☐ Reliability Coordinator	☐ Transmission Service Provider
☐ Balancing Authority	☐ Transmission Owner
☐ Interchange Authority	☐ Load Serving Entity
☐ Planning Authority or Coordinator	☐ Distribution Provider
☐ Transmission Operator	☐ Purchasing-selling Entity
☐ Generator Operator	☐ Generator Owner
☐ Transmission Planner	☐ Resource Planner
☐ Compliance Monitor	☐ Market Operator

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group.	
Name:	Office Telephone:
Organization:	E-mail:
Name:	Office Telephone:
Organization:	E-mail:

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SC approved SAR for initial posting (January 11, 2007).
2. SAR posted for comment (January 15–February 14, 2007).
3. SAR posted for comment (April 10–May 9, 2007).
4. SC authorized moving the SAR forward to standard development (June 27, 2007).

Proposed Action Plan and Description of Current Draft:

This is the initial posting of the proposed revisions to the requirements and measures in the standard. Once there is consensus on the language in the requirements and measures, the drafting team will add compliance elements to the standard.

Future Development Plan:

Anticipated Actions	Anticipated Date
1.	
2.	
3.	
4.	
5.	
6.	
7.	

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Active Transmission Line Right of Way — A strip of land that is occupied by active transmission facilities. This corridor does not include the inactive or unused part of the Right of Way intended for other facilities.

Critical Clearance Zone — The area mapped by the radial distance around a conductor specified in Table I of Attachment 1 to reliability standard FAC-003-2 — Transmission Vegetation Management Program when the conductor is energized and operating between no-load and its Rating, including the design blowout, however, the zone shall not extend beyond the limits of the Active Transmission Line Right of Way.

A. Introduction

1. **Title:** **Transmission Vegetation Management Program**

2. **Number:** FAC-003-2

3. **Purpose:** To improve the reliability of the Bulk Electric System by preventing vegetation related outages that could lead to Cascading.

4. **Applicability**

   4.1. Functional Entities:

   4.1.1. Transmission Owner

   4.1.2. Reliability Coordinator

   4.2. Facilities:

   4.2.1. Transmission lines ("applicable lines") operated at 200kV or higher, and transmission lines operated below 200kV designated by the Reliability Coordinator as being subject to this standard including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities.

   4.2.2. Transmission lines operated below 200kV designated by the Reliability Coordinator as being subject to this standard become subject to this standard 12 months after the date the Reliability Coordinator initially designates the transmission line as being subject to this standard.

   4.2.3. Existing transmission line(s) operated at 200kV or higher that are newly acquired by a Transmission Owner and were not previously subject to this standard, become subject to this standard 12 months after the acquisition date of the transmission line(s).

5. **Effective Dates:**

   In those jurisdictions where regulatory approval is required, the first calendar day of the first calendar quarter one year after applicable regulatory authority approval for all requirements; or, in those jurisdictions where no regulatory approval is required, the first calendar day of the first calendar quarter one year following Board of Trustees adoption.

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies"*

B. Requirements

R1. Each Transmission Owner shall have a documented transmission vegetation management program designed to control vegetation on its Active Transmission Lines' Rights of Way. The transmission vegetation management program shall:

R1.1. Specify the methodologies that the Transmission Owner uses to control vegetation.[2]

R1.2. Specify a vegetation inspection frequency of at least once per calendar year that takes into account local[3] and environmental factors.

R1.3. Require an annual plan that identifies the applicable lines to be maintained and associated work to be performed during the year. It shall be flexible to adjust to changing conditions and to findings from vegetation inspections. Adjustments to the plan within the year are permissible. The plan shall take into consideration permitting and scheduling requirements from landowners or regulatory authorities. It shall support the objectives of the transmission vegetation management program and use the methodologies outlined in the transmission vegetation management program.

R1.4. Require a process or procedure for response to imminent threats of a vegetation related Sustained Outage. The process or procedure shall specify actions which shall include immediate communication of the threat to the Transmission Operator, and may include actions such as a temporary reduction in line Rating, switching lines out of service, or other actions.

R1.5. Specify an interim corrective action process for use when the Transmission Owner is constrained from performing vegetation maintenance as planned.

R2. Each Transmission Owner shall implement its imminent threat procedure when the Transmission Owner has knowledge, obtained through normal operating practices or notification from others, that the Critical Clearance Zone is approached by vegetation to prevent an encroachment of the Critical Clearance Zone.

R3. Each Transmission Owner shall conduct inspections of all applicable lines in accordance with the frequency specified in its transmission vegetation management program.

R4. Each Transmission Owner shall prevent encroachment within the Critical Clearance Zone of its applicable lines with the following exceptions:

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[2] ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

[3] Local factors include treatment cycle, extent and type of treatment, and their relationship to the normal growth rate.

- Encroachments of the Critical Clearance Zone that result from natural disasters.[4]
- Encroachments of the Critical Clearance Zone that result from human or animal activity.[5]

R5. Each Transmission Owner shall prevent Sustained Outages of applicable lines[6] due to vegetation growing into a conductor operating between no-load and its Rating with the following exceptions:

- Sustained Outages of applicable lines that result from natural disasters.[4]
- Sustained Outages of applicable lines that result from human or animal activity.[5]

R6. Each Transmission Owner shall prevent Sustained Outages of applicable lines[6] due to the blowing together of vegetation and a conductor within an Active Transmission Line Right of Way (operating within design blow-out conditions) with the following exception:

- Sustained Outages of applicable lines that result from sustained winds or gusts due to natural disasters.4

R7. Each Transmission Owner shall prevent Sustained Outages of applicable lines[6] due to vegetation falling into a conductor from within an Active Transmission Line Right of Way with the following exceptions:

- Sustained Outages of applicable lines that result from natural disasters.[4]
- Sustained Outages of applicable lines that result from human or animal activity.[5]

R8. Each Transmission Owner shall implement its annual work plan for vegetation management to accomplish the purpose of this standard within the extent of its easement and/or legal rights.

R9. Each Reliability Coordinator in consultation with its Transmission Owner(s) and neighboring Reliability Coordinator(s) shall jointly prepare and keep current, a list of designated applicable lines that are operated below 200kV, if any, which are subject to this standard.

R10. Each Reliability Coordinator shall document its method for assessing the reliability significance of sub-200kV lines considering all of the following:

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[4] Examples include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods.

[5] Examples include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation.

[6] Multiple Sustained Outages on an individual line, if caused by the same vegetation, shall be considered as one outage regardless of the actual number of outages within a 24-hour period.

R10.1 Transmission lines whose loss would result in the exceedance of an Interconnection Reliability Operating Limit (IROL)

R10.2 Transmission lines whose loss would place the grid at an unacceptable risk of instability, separation, or cascading failures.

B. Measures

M1. The Transmission Owner has a documented transmission vegetation management program designed to control vegetation on the Active Transmission Line Right of Way. (R1)

M1.1 The Transmission Owner's transmission vegetation management program specifies the methodologies that the Transmission Owner uses to control vegetation.

M1.2 The Transmission Owner's transmission vegetation management program specifies a vegetation inspection frequency that takes into account local and environmental factors. This inspection frequency shall be at least once per calendar year.

M1.3 The Transmission Owner's transmission vegetation management program requires an annual plan and it identifies the applicable lines to be maintained and related vegetation management work to be performed during the calendar year while taking into consideration permitting and scheduling requirements from landowners or regulatory authorities.

M1.4 The Transmission Owner's transmission vegetation management program requires an imminent threat process or procedure for responding to imminent threats of a vegetation-related Sustained Outage including immediate communication of the threat to the Transmission Operator, and may include a temporary reduction in line Rating, switching lines out of service, and/or other actions that may be taken until the threat is relieved.

M1.5 The Transmission Owner's transmission vegetation management program specifies the interim corrective action process for use when the Transmission Owner is constrained from performing vegetation maintenance as planned.

M2. The Transmission Owner has evidence that it implemented its imminent threat procedure when it obtained knowledge that the Critical Clearance Zone was approached by vegetation. (R2)

M3. The Transmission Owner has evidence that it conducted vegetation inspections of all applicable transmission lines in accordance with the frequency specified in its transmission vegetation management program. (R3)

M4. The Transmission Owner has evidence such as inspection records, imminent threat reports or quality assurance reports, demonstrating there were no vegetation encroachments into the Critical Clearance Zone. (R4)

M5. The Transmission Owner has evidence that there was not a Sustained Outage of an applicable line due to vegetation growing into a conductor operating between no-load and its Rating. (R5)

M6. The Transmission Owner has evidence that there was not a Sustained Outage of an applicable line due to the blowing together of vegetation and a conductor within the Active Transmission Line Right of Way. (R6)

M7. The Transmission Owner has evidence that there was not a Sustained Outage of an applicable line due to vegetation falling into a conductor from within the Active Transmission Line Right of Way. (R7)

M8. The Transmission Owner has evidence that it is implementing, or has implemented, its annual work plan. (R8)

M9. The Reliability Coordinator has evidence that it consulted with its Transmission Owner(s) and adjacent Reliability Coordinator(s), prepared and kept current a list of designated sub-200kV transmission lines, if any, which are subject to this standard. (R9)

M10. The Reliability Coordinator has evidence that it has defined its methods for assessing the reliability significance of sub-200kV lines and has developed selection criteria for listing any sub-200kV lines. (R10)

C. Compliance (To be added)

D. Regional Differences

None identified.

E. Associated Technical Reference Documents

FAC-003 Reference — Transmission Vegetation Management — White Paper.

Version History

Version	Date	Action	Change Tracking
1	TBA	1. Added “Standard Development Roadmap.” 2. Changed “60” to “Sixty” in section A, 5.2. 3. Added “Proposed Effective Date: April 7, 2006” to footer. 4. Added “Draft 3: November 17, 2005” to footer.	01/20/06
1	April 4, 2007	Regulatory Approval — Effective Date	New

FAC-003-2 Attachment 1

The Critical Clearance Zone is the area mapped by the radial distance around a conductor specified in Table I below when the conductor is energized and operating between no-load and its Rating, including the design blow-out, however, the zone shall not extend beyond the limits of the Active Transmission Line Right of Way.

TABLE I — Minimum Vegetation Clearance Distances

For Alternating Current Voltages

(AC) Nominal System Voltage (kV)	**(AC) Maximum System Voltage (kV)**	**D feet (meters) sea level**	**D feet (meters) 3,000ft (914.4m)**	**D feet (meters) 4,000ft (1219.2m)**	**D feet (meters) 5,000ft (1524m)**	**D feet (meters) 6,000ft (1828.8m)**
765	800	8.06ft (2.46m)	8.89ft (2.71m)	9.17ft (2.80m)	9.45ft (2.88m)	9.73ft (2.97m)
500	550	5.06ft (1.54m)	5.66ft (1.73m)	5.86ft (1.79m)	6.07ft (1.85m)	6.28ft (1.91m)
345	362	3.12ft (0.95m)	3.53ft (1.08m)	3.67ft (1.12m)	3.82ft (1.16m)	3.97ft (1.21m)
230	242	2.97ft (0.91m)	3.36ft (1.02m)	3.49ft (1.06m)	3.63ft (1.11m)	3.78ft (1.15m)
161*	169	2ft (0.61m)	2.28ft (0.69m)	2.38ft (0.73m)	2.48ft (0.76m)	2.58ft (0.79m)
138*	145	1.7ft (0.52m)	1.94ft (0.59m)	2.03ft (0.62m)	2.12ft (0.65m)	2.21ft (0.67m)
115*	121	1.41ft (0.43m)	1.61ft (0.49m)	1.68ft (0.51m)	1.75ft (0.53m)	1.83ft (0.56m)
88*	100	1.15ft (0.35m)	1.32ft (0.40m)	1.38ft (0.42m)	1.44ft (0.44m)	1.5ft (0.46m)
69*	72	0.82ft (0.25m)	0.94ft (0.29m)	0.99ft (0.30m)	1.03ft (0.31m)	1.08ft (0.33m)

*As designated by the Reliability Coordinator

TABLE I — Minimum Vegetation Clearance Distances (D)

For Alternating Current Voltages

(AC) Nominal System Voltage (kV)	(AC) Maximum System Voltage (kV)	D feet (meters) 7,000ft (2133.6m)	D feet (meters) 8,000ft (2438.4m)	D feet (meters) 9,000ft (2743.2m)	D feet (meters) 10,000ft (3048m)	D feet (meters) 11,000ft (3352.8m)
765	800	10.01ft (3.05m)	10.29ft (3.14m)	10.57ft (3.22m)	10.85ft (3.31m)	11.13ft (3.39m)
500	550	6.49ft (1.98m)	6.7ft (2.04m)	6.92ft (2.11m)	7.13ft (2.17m)	7.35ft (2.24m)
345	362	4.12ft (1.26m)	4.27ft (1.30m)	4.43ft (1.35m)	4.58ft (1.40m)	4.74ft (1.44m)
230	242	3.92ft (1.19m)	4.07ft (1.24m)	4.22ft (1.29m)	4.37ft (1.33m)	4.53ft (1.38m)
161*	169	2.69ft (0.82m)	2.8ft (0.85m)	2.91ft (0.89m)	3.03ft (0.92m)	3.14ft (0.96m)
138*	145	2.3ft (0.70m)	2.4ft (0.73m)	2.49ft (0.76m)	2.59ft (0.79m)	2.7ft (0.82m)
115*	121	1.91ft (0.58m)	1.99ft (0.61m)	2.07ft (0.63m)	2.16ft (0.66m)	2.25ft (0.69m)
88*	100	1.57ft (0.48m)	1.64ft (0.50m)	1.71ft (0.52m)	1.78ft (0.54m)	1.86ft (0.57m)
69*	72	1.13ft (0.34m)	1.18ft (0.36m)	1.23ft (0.37m)	1.28ft (0.39m)	1.34ft (0.41m)

*As designated by the Reliability Coordinator

TABLE I — Minimum Vegetation Clearance Distances (D)
For Direct Current Voltages

(DC) Pole to Pole Nominal Voltage (kV)	**D feet (meters) sea level**	**D feet (meters) 3,000ft (914.4m) Alt.**	**D feet (meters) 4,000ft (1219.2m) Alt.**	**D feet (meters) 5,000ft (1524m) Alt.**	**D feet (meters) 6,000ft (1828.8m) Alt.**
1500	13.92ft (4.24m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)
1200	10.07ft (3.07m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)
1000	7.89ft (2.40m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)
800	4.78ft (1.46m)	5.35ft (1.63m)	5.55ft (1.69m)	5.75ft (1.75m)	5.95ft (1.81m)
500	3.43ft (1.05m)	4.02ft (1.23m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)

Pole to Pole Nominal Voltage (kV)	**D feet (meters) 7,000ft (2133.6m) Alt.**	**D feet (meters) (8,000ft (2438.4m) Alt.**	**D feet (meters) 9,000ft (2743.2m) Alt.**	**D feet (meters) 10,000ft (3048m) Alt.**	**D feet (meters) 11,000ft (3352.8m) Alt.**
1500	16.55ft (5.04m)	16.9ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
1200	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	(13.54ft 4.13m)
1000	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
800	6.15ft (1.87m)	6.36ft (1.94m)	6.57ft (2.00m)	6.77ft (2.06m)	6.98ft (2.13m)
500	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5ft (1.52m)	5.17ft (1.58m)

FAC-003-1 Mapping to Revised NERC Reliability Standard FAC-003-2

Standard FAC-003-1 NERC Board Approved	Comment	Proposed Standard FAC-003-2
1. Title: Transmission Vegetation Management Program	**1. Title:** No Change (N/C)	**1. Title:** Transmission Vegetation Management Program
2. Number: FAC-003-1	**2. Number:** Update to latest Revision	**2. Number:** FAC-003-2
3. Purpose: To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetationrelated outages of the transmission systems to the respective Regional Reliability Organizations (RRO) and the North American Electric Reliability Council (NERC).	**3. Purpose:** Changed electric transmission systems to Bulk Electric System. Changed to a shorter more concise purpose statement. The various explanatory objectives are now addressed within the standard's requirements.	**3. Purpose:** To improve the reliability of the Bulk Electric System by preventing vegetation related outages that could lead to widespread cascading failures.
4. Applicability: 4.1. Transmission Owner 4.2. Regional Reliability Organization 4.3. This standard shall apply to all transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RRO as critical to the reliability of the electric system in the region.	**4. Applicability:** **Separated applicability between functional entities and facilities for clarity** 4.1 now is 4.4.1 No change 4.2 Removed Regional Reliability Organization and added 4.1.2 Reliability Coordinator 4.3 Clarified facility applicability in 4.2, 4.2.1, 4.2.2 and 4.2.3 as stated below 4.2.1. Added term "applicable lines" for format efficiency in the standard verbiage. Ensures that all lines are covered by the standard regardless of the owner of the over which they cross.	**4.** Applicability 4.1 Functional Entities: 4.1.1 Transmission Owner 4.1.2 Reliability Coordinator 4.2 Facilities: 4.2.1 Transmission lines ("applicable lines") operated at 200kV or higher, and transmission lines operated below 200kV designated by the Reliability Coordinator as being subject to this standard including but not limited to those that cross lands owned by federal, state, provincial, public, private, or

Standard FAC-003-1 NERC Board Approved	Comment	Proposed Standard FAC-003-2
	4.2.2 Added to identify the time frame allowed to bring sub 200kV lines into compliance with the standard after the Reliability Coordinator has determined that they are subject to the standard. 4.2.3. Added to specify the time frame allowed, for a newly acquired above 200kV line, which was not previously subject to the standard, to become subject to the standard.	tribal entities. 4.2.2 Transmission lines operated below 200kV designated by the Reliability Coordinator as being subject to this standard become subject to this standard 12 months after the date the Reliability Coordinator initially designates the transmission line as being subject to this standard. 4.2.3 Existing transmission line(s) operated at 200kV or higher that are newly acquired by a Transmission Owner and were not previously subject to this standard, become subject to this standard 12 months after the acquisition date of the transmission line(s).
Effective Dates: **5.1** One calendar year from the date of adoption by the NERC Board of Trustees for Requirement 1 and 2. **5.2** Sixty calendar days from the date of adoption by the NERC Board of Trustees for the Requirements 3 and 4.	**Effective Dates:** Reworded both 5.1 and 5.2 as one statement for consistency with standards process for a standard revision.	5. **Effective Dates:** In those jurisdictions where regulatory approval is required, the first calendar day of the first calendar quarter one year after applicable regulatory authority approval for all requirements; or, in those jurisdictions where no regulatory approval is required, the first calendar day of the first calendar quarter one year following Board of Trustees adoption.
R1. The Transmission Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the Transmission Owner's objectives, practices, approved procedures, and work specifications.	**R1.** Replaced "prepare, and keep current" with "have" and removed the longer series of terms with one term "designed to control vegetation". Clarified that this applies on the Active Transmission Line Right of Way. **R1.1** New language replaced the longer series that was	**R1**. Each Transmission Owner shall have a documented transmission vegetation management program designed to control vegetation on its Active Transmission Lines' Rights of Way. The transmission vegetation management program shall: **R1.1.** Specify the methodologies that the Transmission

Standard FAC-003-1 NERC Board Approved	Comment	Proposed Standard FAC-003-2
R1.1. The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the Transmission Owner's transmission lines. **R2.** The Transmission Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.	previously implied by **R1** in version 1. **R1.1 replaced by R1.2.** Changed inspection schedule to inspection frequency and specified the frequency to be at least once per calendar year. Note also that **R3** has been added to clarify that the conduction of inspections is a separate requirement from specifying the frequency that inspections will occur. **R2** replaced by **R1.3** and **R8.** **R1.3** is the explanation of the TVMP documentation requirements changes only. See the associated remarks below under **R8** for the changes with respect to implementation of the annual plan.	Owner uses to control vegetation. **R1.2.** Specify a vegetation inspection frequency of at least once per calendar year that takes into account local[1] and environmental factors. **R1.3.** Require an annual plan that identifies the applicable lines to be maintained and associated work to be performed during the year. It shall be flexible to adjust to changing conditions and to findings from vegetation inspections. Adjustments to the plan within the year are permissible. The plan shall take into consideration permitting and scheduling requirements from landowners or regulatory authorities. It shall support the objectives of the transmission vegetation management program and use the methodologies outlined in the transmission vegetation management program.

FAC-003-1 Mapping to Revised NERC Reliability Standard FAC-003-2

Standard FAC-003-1 NERC Board Approved	Comment	Proposed Standard FAC-003-2
R1.5. Each Transmission Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved. **R1.4.** Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner is restricted from attaining the clearances specified in Requirement 1.2.1.	**R1.5** replaced by **R1.4** which requires a documented process to respond with examples of actions including immediate communications and other actions that may be taken to relieve the threat. **R1.4** replaced by **R1.5** – Now referred to as interim corrective action process to address situations where vegetation maintenance activities cannot be performed as planned. The term corrective action plan is used in lieu of mitigation plan to avoid confusion with other uses in NERC of "mitigation plan" **New R2** added to ensure that implementation of the imminent threat procedure as a stand-alone requirement. **R3.** Has been added to separate this conduct of inspections from **R1.2** documentation which specifies the frequency for inspections. **The old R1.2.** Has been changed by elimination of Clearance 1 and the replacement of Clearance 2 with the Critical Clearance Zone. See **R2** and **R4**	**R1.4.** Require a process or procedure for response to imminent threats of a vegetation related Sustained Outage. The process or procedure shall specify actions which shall include immediate communication of the threat to the Transmission Operator, and may include actions such as a temporary reduction in line rating, switching lines out of service, or other actions. **R1.5.** Specify the general interim corrective action process for use when the Transmission Owner is constrained from performing vegetation maintenance as planned. **R2.** Each Transmission Owner shall implement its imminent threat procedure when the Transmission Owner has knowledge, obtained through normal operating practices or notification from others, that the Critical Clearance Zone is approached by vegetation to prevent an encroachment of the Critical Clearance Zone. **R3**.Each Transmission Owner shall conduct inspections of all applicable lines in accordance with the frequency specified in its transmission vegetation management program.

Standard FAC-003-1 NERC Board Approved	Comment	Proposed Standard FAC-003-2
R1.2. The Transmission Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading and the effects of wind velocities on conductor sway. Specifically, the Transmission Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors. **R1.2.1.** Clearance 1 — The Transmission Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner plans to return for future vegetation management work. Local conditions include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species type and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation location of the vegetation within the span, and worker approach distance requirements, Clearance 1 distances shall be greater than those defined by Clearance 2 below under all rated electrical operating conditions.	**R1.2.1 -** Clearance 1 requirement eliminated: **R1.2.2** replaced by **R4 -** Clearance 2 has been replaced by Critical Clearance Zone. the old **R1.1.2** was a documentation requirement within the TVMP whereas **R4** specifies encroachments as violations. Under the Levels of Non-Compliance in **FAC-003-1, Level 3: 2.3.2** covered failure to "maintain…Clearance 2". Note that encroachment reporting will be addressed later in a **VSL** for **R4**	**R4** Each Transmission Owner shall prevent encroachment within the Critical Clearance Zone of

Standard FAC-003-1 NERC Board Approved	Comment	Proposed Standard FAC-003-2
R1.2.2. Clearance 2 — The Transmission Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These Transmission Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap. **R1.2.2.1** Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied. **R1.2.2.2** Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied **R1.3.** All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner, to perform their duties.	 **R1.3** – Personnel qualifications has been removed.	its applicable lines with the following exceptions: 1. Encroachments of the Critical Clearance Zone that result from natural disasters. 2. Encroachments of the Critical Clearance Zone that result from human or animal activity.
R3. The Transmission Owner shall report quarterly to	**R3** Outage reporting is now covered in **R5-R7** and	**R5** Each Transmission Owner shall prevent Sustained

Standard FAC-003-1 NERC Board Approved	Comment	Proposed Standard FAC-003-2
its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission Owner to have been caused by vegetation. **R3.1.** Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24-hour period. **R3.2.** The Transmission Owner is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation). **R3.3.** The outage information provided by the Transmission Owner to the RRO, or the RRO's designee, shall include at a minimum: the name	**M5-M7** and the associated Compliance **VSLs** for **R5-R7.** Requirements **R5, R6, and R7** specify three types of Sustained Outages which shall be prevented. Exceptions have been further defined Outages in **FAC-003-1 R3** were reporting requirements and were not violations per se. In that version of the standard the **Levels of Non-Compliance 2.2.3, 2.3.1**, and **2.4.1** the Sustained Outages were assigned a level of non-compliance.	Outages of applicable lines due to vegetation growing into a conductor operating between no-load and rated conditions with the following exceptions: 1. Sustained Outages of applicable lines that result from natural disasters. 2. Sustained Outages of applicable lines that result from human or animal activity. **R6** Each Transmission Owner shall prevent Sustained Outages of applicable lines due to the blowing together of vegetation and a conductor within an Active Transmission Line Right of Way(operating within design blow out conditions) with the following exception: 1. Sustained Outages of transmission lines that result from sustained winds or gusts due to natural disasters. **R7** Each Transmission Owner shall prevent Sustained Outages of applicable lines due to vegetation falling into a conductor from within an Active Transmission Line Right of Way with the following exceptions: 1. Sustained Outages of applicable lines that result from natural disasters. 2. Sustained Outages of applicable lines that result from human or animal activity.

Standard FAC-003-1 NERC Board Approved	Comment	Proposed Standard FAC-003-2
of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner. **R3.4.** An outage shall be categorized as one of the following: **R3.4.1.** Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW; **R3.4.2.** Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW; **R3.4.3.** Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.	Category 3 – fall-in outages are no longer reportable. . **R8** Is a new requirement which separates the implementation of the annual plan from the creation of the annual plan. See **FAC-003-2, 1.3** above.	**R8** Each Transmission Owner shall implement its annual work plan for vegetation management to accomplish the purpose of this standard within the extent of its easement and/or legal rights.
R4. The RRO shall report the outage information provided to it by Transmission Owner's, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the RRO as a result of any of the reported outages.	**R4** Eliminated. The RRO, which is now the RE, is not subject to standards.	
	R9 This new requirement addresses the	**R9** Each Reliability Coordinator in consultation

Standard FAC-003-1 NERC Board Approved	Comment	Proposed Standard FAC-003-2
	identification of sub-200kV lines.	with their Transmission Owner(s) and neighboring Reliability Coordinator(s) shall jointly prepare and keep current, a list of designated applicable lines that are operated below 200kV, if any, which are subject to this standard.
		R10 Each Reliability Coordinator shall document its method for assessing the reliability significance of sub-200kV lines considering all of the following: **R10.1** Transmission lines whose loss would result in the exceedance of an Interconnection Reliability Operating Limit (IROL) **R10.2** Transmission lines whose loss would place the grid at an unacceptable risk of instability, separation, or cascading failures.
	Footnotes have been added to reference the EPact 2005 and to define the active transmission line ROW	Footnotes on Page 2
	Footnote added to define local factors	Footnotes on Page 3
	Footnotes added to cover exceptions which were in FAC-003-1 imbedded within the standard	Footnotes on Page 4

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

First Draft of Standards for Vegetation Management (Project 2007-07)

First draft of the FAC-003-2 — Transmission Vegetation Management Program standard for the Vegetation Management Standard Drafting Team (Project 2007-07) is up for a 30-day comment period. Comments must be submitted through the electronic comment form by **November 25, 2008.** If you have questions please contact Harry Tom at Harry.Tom@nerc.net or by telephone at 860-550-4157

Background Information:

The Standard Drafting Team revised the Vegetation Management Standard in accordance with the Standard Authorization Request. The Standard Authorization Request scope reflects comments from the FERC Order 693 and from stakeholders as well as procedural updates. The Standard Authorization Request also specified that the revised standard incorporate compliance program elements of time horizons, violation severity levels, etc. to bring it into conformance with the latest version of the Reliability Standard Development Procedure and the ERO Sanctions Guidelines. The compliance elements are not included in this initial posting. The Standard Drafting Team has prepared a Technical Reference document to supplement the FAC-003-2 Standard and is posted along with the revised standard. This posting seeks comment on the Standard revision as well as the Technical Reference document.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. In the Purpose Statement the term "electric transmission systems" was changed to Bulk Electric System, and the Purpose statement was shortened by moving the various explanatory objectives to other locations in the revised Standard. Do you agree with the purpose statement? If not, please explain.

   ☐ Agree

   ☐ Disagree

   Comments:

2. The Reliability Coordinator was chosen as the proper entity to identify sub-200kV transmission lines to be subject to this standard (see applicability, R9, and R10). Do you agree with this choice? If not, please explain.

   ☐ Agree

   ☐ Disagree

   Comments:

3. In R1 the proposed standard replaces "*prepare, and keep current*" with "*have*", replaces the list of terms, "*objectives, practices, approved procedures, and work specifications*," with "*designed to control vegetation*", defines the "active transmission line ROW", and specifies that the transmission vegetation management program applies to that area. Do you agree with R1? If not, please explain.

   ☐ Agree

   ☐ Disagree

   Comments:

4. Documentation and implementation of the transmission vegetation management program which were previously combined in Requirement R1 are now separated in order to apply appropriate VRFs and time horizons. The implementation of some elements has been moved into standalone requirements such as inspection cycles (R3) and annual plan implementation (R8). Do you agree with these revisions and separation? If not, please explain.

   ☐ Agree

   ☐ Disagree

   Comments:

5. In R1.2 the Transmission Owner is required to have an inspection frequency of at least once per calendar year. Do you agree with R1.2? If not, please explain.

   ☐ Agree

   ☐ Disagree

   Comments:

6. In R1.3 the Standard requires that transmission vegetation management program specify an Annual Plan and specifies parameters for the plan. Implementation of the Annual Plan is separated and placed in R8. Do you agree with R1.3 and the separation of the implementation from the specification of the Annual Plan? If not, please explain.

☐ Agree

☐ Disagree

Comments:

7. In R1.4 the Standard requires the Transmission Owner to have an Imminent Threat Procedure and specifies elements to be in that procedure. Do you agree with R1.4? If not, please explain.

☐ Agree

☐ Disagree

Comments:

8. Requirement 1 section R1.5 replaces Version 1 sub-requirement R1.4. This section is now referred to as interim corrective action process. This process addresses situations where vegetation maintenance activities cannot be performed as planned. The term *corrective action plan* is used in lieu of *mitigation plan* to avoid confusion with other uses in NERC of "*mitigation plan*". Do you agree with R1.5? If not, please explain.

☐ Agree

☐ Disagree

Comments:

9. Clearance 1 in Version 1 was a "fill-in-the-blank" requirement and was removed from the standard. Do you agree? If not, please explain.

☐ Agree

☐ Disagree

Comments:

10. Personnel Qualifications in R1.3 in Version 1 was a "fill-in-the-blank" requirement and was removed from Version 2 of the standard. Do you agree? If not please explain.

☐ Agree

☐ Disagree

Comments:

11. The IEEE 516 standard distances were replaced with the Gallet equation distances. Clearance 2 was replaced by the Critical Clearance Zone. The Critical Clearance Zone is defined as the zone of all possible positions of the conductor at the line's designed operating ratings including wind factors. (Please refer to pages 22-32 in the Technical Reference Document on the Critical Clearance Zone for further background for this question.) The imminent threat procedure, R2, requires action to be taken to prevent an outage when the Critical Clearance Zone is approached. Do you agree with R2? If not please explain.

☐ Agree

☐ Disagree

Comments:

12. The Standard Drafting Team revised the spark-over (also referred to as "flashover") distance thresholds utilizing technically-equivalent Gallet equations in lieu of IEEE 516 minimum air insulation distance (MAID) calculations that were used in FAC-003-1. The rationale is that the minimum air insulation distances in IEEE 516 were safety clearances developed under laboratory conditions and thus there exists concern these distances may be too conservative to apply to lines operating in actual field conditions. Do you agree with this? If not, please explain.

☐ Agree

☐ Disagree

Comments:

13. The Standard Drafting Team applied a transient overvoltage factor (T) of 1.4 and 2.0 for ac voltage classes of 345kV and above and sub-345kV facilities, respectively. Version 1, using the IEEE 516 method, assumes a maximum transient overvoltage value. The Standard Drafting Team asserts that in this application of steady-state flashovers and due to the design attributes of higher voltage systems, a lower T factor is applicable. Do you agree with this? If not, please explain.

☐ Agree

☐ Disagree

Comments:

14. R3 has been added to clarify that conduction of inspections is a separate requirement from specifying the frequency that inspections will occur. Do you agree with R3? If not please explain.

☐ Agree

☐ Disagree

Comments:

15. Several alternatives to R4 were considered by the drafting team. The drafting team explored these significantly different alternatives at length. They are outlined below to provide background to industry during this comment period. (Please refer to pages 22-32 in the Technical Reference Document on the Critical Clearance Zone for further background for this question.)

    - As written, R4, a new requirement, stipulates that the Transmission Owner is in violation if an encroachment of the Critical Clearance Zone occurs at any time. If vegetation enters the Critical Clearance Zone, a violation will have occurred, regardless of the actual proximity of the vegetation to the conductor at the time. Evidence will be required to prove that no encroachments of the Critical Clearance Zone have occurred anywhere at any time during the annual compliance period. This will require the time and effort to postpone vegetation maintenance to perform field investigations and document all possible encroachments.

    - One alternative to R4 required immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the Critical Clearance Zone, thereby proactively preventing an outage. A violation would have occurred only if the imminent threat process was not successfully implemented.

- Another alternative was a tiered approach. This tiered approach involved a "per thousand mile" metric to determine when a violation had occurred and the severity of the violation. This metric was an attempt to equitably account for varying exposures that exist due to widely ranging system sizes.

Do you agree that R4 is written in the most effective way to achieve the purpose of the standard? If not, what do you propose as an alternative to R4 that would ensure a level of reliability equal to or better than FAC-003-1?

☐ Agree

☐ Disagree

Comments:

16. Requirements R5, R6, and R7 define that Sustained Outages due to vegetation growing into, blowing together with, and falling into transmission lines are violations (subject to certain exemptions). Therefore, all such outages must be reported as violations of the standard. Do you agree with this change? If not, please explain.

☐ Agree

☐ Disagree

Comments:

17. R8 is a new requirement which separates the implementation of the annual plan from the requirement to have an annual plan. Do you agree with R8? If not please explain.

☐ Agree

☐ Disagree

Comments:

18. If you have further suggestions for improving this standard or the technical reference document, please offer them.
Comments:

Transmission Vegetation Management

NERC Standard FAC-003-2 Technical Reference

Prepared by the

North American Electric Reliability Corporation

Vegetation Management Standard Drafting Team

OCTOBER 20, 2008

Table of Contents

Introduction

This document is intended to provide supplemental information and guidance for complying with the requirements of Reliability Standard FAC-003-2. It is a supporting document and provides explanatory background to the requirements of the Standard.

The purpose of the Standard is to improve the reliability of the Bulk Electric System by preventing vegetation related outages that could lead to Cascading.

Compliance with the Standard is mandatory and enforceable.

Disclaimer

This supporting document may explain or facilitate implementation of reliability standard FAC-003-2 — Transmission Vegetation Management but does not contain mandatory requirements subject to compliance review.

Definition of Terms

Active Transmission Line Right of Way* — A strip of land that is occupied by active transmission facilities. This corridor does not include the inactive or unused part of the Right-of-Way intended for other facilities.

Examples of active and inactive portions of corridors include:

1) Where portions of the right of way are occupied by active facilities and other portions are acquired to accommodate future facilities. Power plant exits are examples where large rights-of-way are obtained for maximum corridor utilization and may currently have fewer structures constructed (see Figure 1 on page 6).
2) Rights of way where corridor edge zones are provided for vegetation to exist (see Figure 2 on page 7).
3) Where double-circuit structures are installed but only one circuit is currently strung with conductors (see Figure 3 on page 8).

Critical Clearance Zone* — The area mapped by the radial distance around a conductor specified in Table I of Attachment 1to the reliability standard FAC-003-2 — Transmission Vegetation Management Program when the conductor is energized and operating between no-load and its Rating, including the design blow-out, however the zone shall not extend beyond the limits of the Active Transmission Line Right of Way.

Sustained Outage** — The deenergized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure.

Cascading ** — The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

Rating ** — The operational limits of a transmission system element under a set of specified conditions.

*To be added to the NERC glossary of terms with final approval of this standard revision
** Currently defined in the NERC glossary of terms

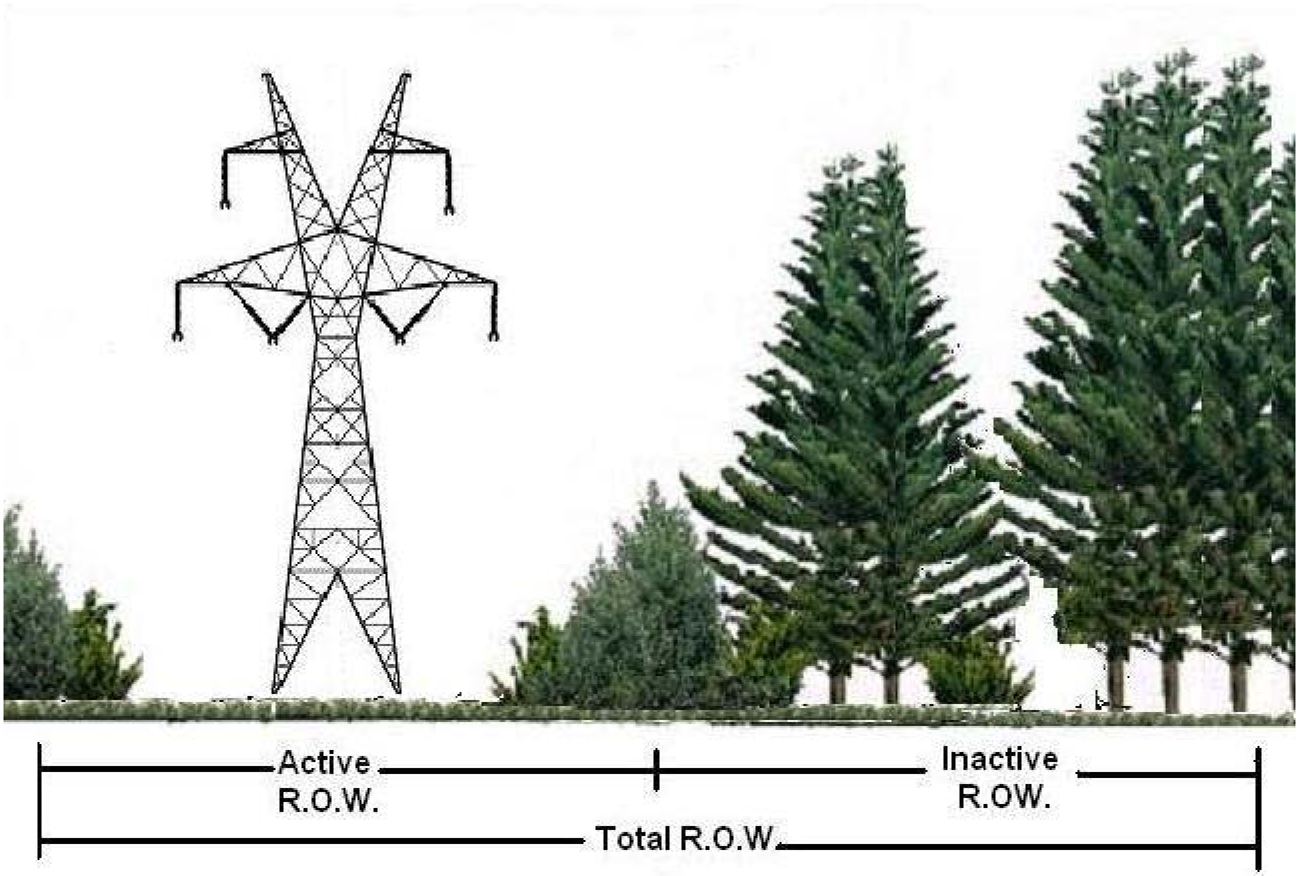

Figure 1

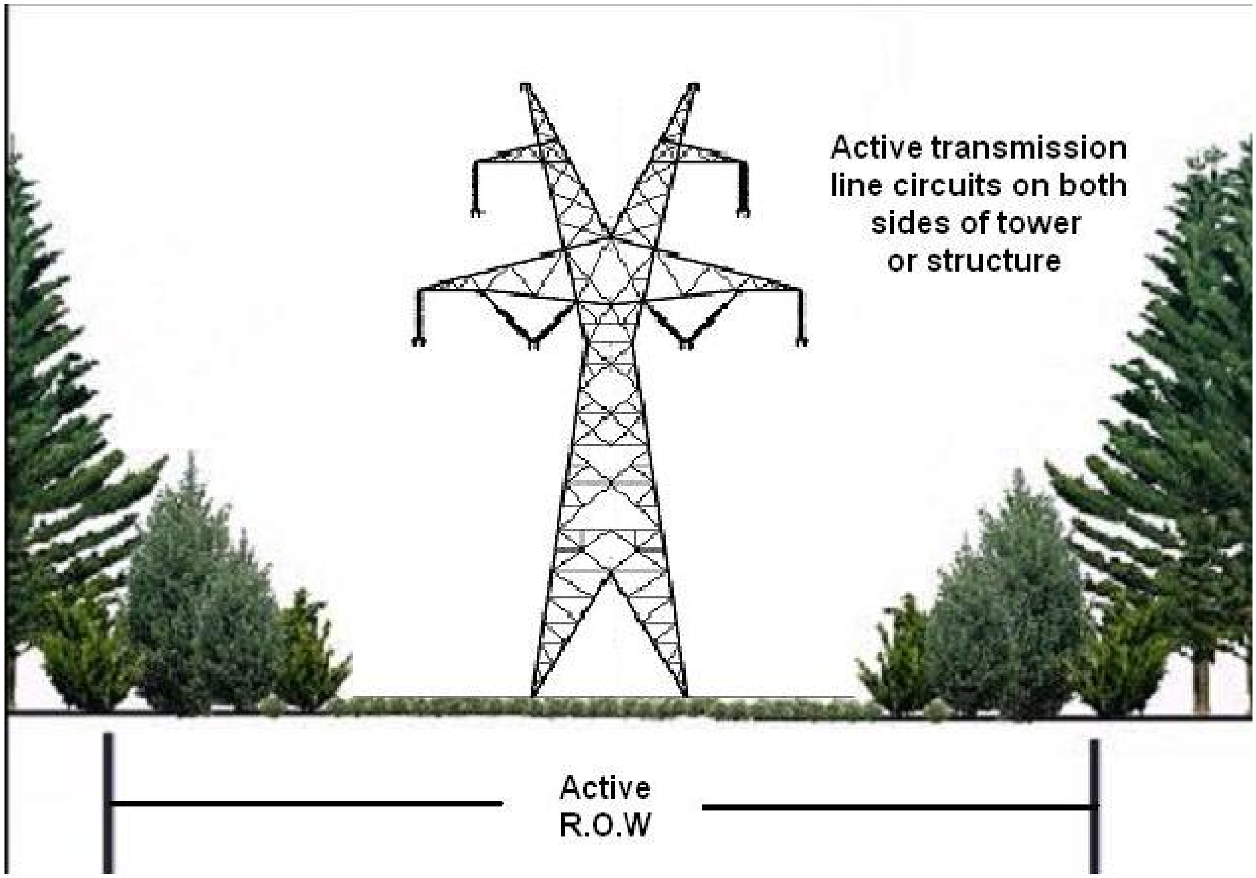
Active transmission
line circuits on both
sides of tower
or structure
Active
R.O.W

Figure 2

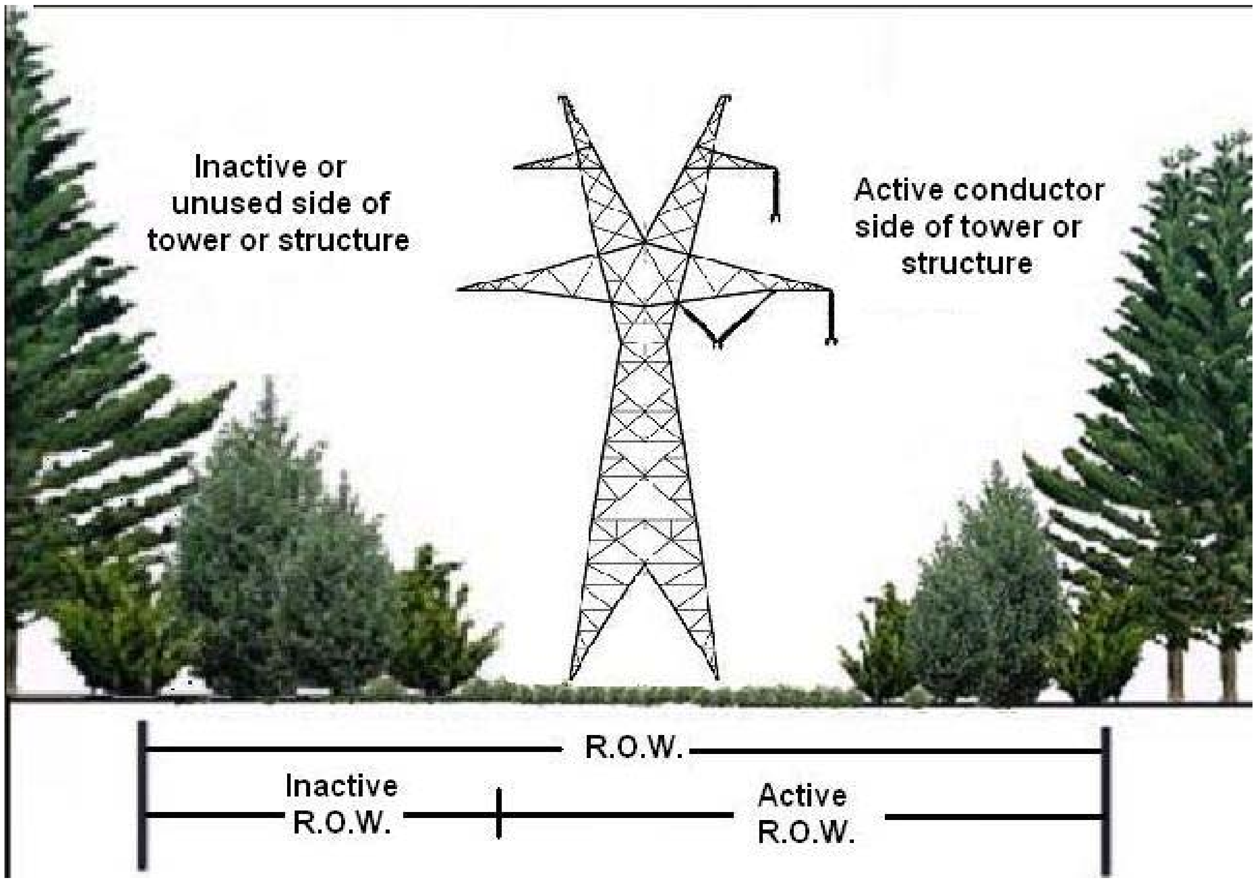
Inactive or
unused side of
tower or structure
Active conductor
side of tower or
structure
R.O.W.
Inactive
R.O.W.
Active
R.O.W.

Figure 3

Applicability of the Standard

4. *Applicability:*

   4.1. Functional Entities:

   4.1.1. Transmission Owner

   4.1.2. Reliability Coordinator

   4.2. Facilities:

   4.2.1. Transmission lines ("applicable lines") operated at 200kV or higher, and transmission lines operated below 200kV designated by the Reliability Coordinator as being subject to this standard including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities.

   4.2.2. Transmission lines operated below 200kV as designated by the Reliability Coordinator as being subject to this standard become subject to this standard 12 months after the date the Reliability Coordinator initially designates the Transmission Line as being subject to this standard.

   4.2.3. Existing transmission line(s) operated at 200kV or higher that are newly acquired by a Transmission Owner and were not previously subject to this standard, become subject to this standard 12 months after the acquisition date of the transmission line(s).

The reliability objective of this NERC Vegetation Management Standard ("Standard") is to prevent vegetation-related outages which could lead to Cascading by effective vegetation maintenance while recognizing that certain outages such as those due to vandalism, human errors and acts of nature are not preventable. Operating experience clearly indicates that trees that have grown out of specification could contribute to a cascading grid failure, especially under heavy electrical loading conditions.

Serious outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. To properly reduce and manage this risk, it is necessary to apply the Standard to applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee.

The Standard addresses vegetation management along applicable overhead lines that serve to connect one electric station to another. However, it is not intended to be applied to lines sections inside the electric station fence or other boundary of an electric station or underground lines.

The Standard is intended to reduce the risk of Cascading involving vegetation. It is not intended to prevent customer outages from occurring due to tree contact with all transmission lines and

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies"*

voltages. For example, localized customer service could be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. This Standard is not written to address such isolated situations which have little impact on the overall Bulk Electric System.

Vegetation growth is constant and always present. Unmanaged vegetation poses an increased outage risk when numerous transmission lines are operating at or near their Rating as a result of increased sags incurred. This poses a significant risk of multiple line failures and Cascading. On the other hand, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are statistically intermittent. The probability of occurrence of these events is not dependent on heavy loads. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these type events are highly unlikely to cause large-scale grid failures.

In preparing the original vegetation management standard in 2005, industry stakeholders set the threshold for applicability of the standard at 200kV. This was because an unexpected loss of lines operating at above 200kV has a higher probability of initiating a widespread blackout or cascading outages compared with lines operating at less than 200kV.

The original NERC vegetation management standard also allowed for application of the standard to “critical” circuits (critical from the perspective of initiating widespread blackouts or cascading outages) operating below 200kV. While the percentage of these circuits is relatively low (at one major U.S. utility, only 3% of its thousands of sub-200kV circuits are considered critical), it remains a fact that there are sub-200kV circuits whose loss could contribute to a widespread outage. Given the very limited exposure and unlikelihood of a major event related to these lower-voltage lines, it would be an imprudent use of resources to apply the Standard to all sub-200kV lines. The drafting team selected, after evaluating several alternatives, the Reliability Coordinator as the best entity to determine applicable lines below 200 kV that are subject to this standard.

Transmission Vegetation Management Program

R1. *Each Transmission Owner shall have a documented transmission vegetation management program designed to control vegetation on its Active Transmission Lines' Rights of Way. The transmission vegetation management program shall:*

The purpose of the Standard is to prevent vegetation-related outages that can result in Cascading. Under Requirement R1, each Transmission Owner is required to have a transmission vegetation management program designed to control vegetation on the Active Transmission Line Right of Way. The transmission vegetation management program is an important component of the Standard because it is the formal document that Transmission Owners use to manage vegetation to achieve the purpose of the Standard. An adequate transmission vegetation management program formally establishes the guidelines that are used by the Transmission Owner to plan and perform vegetation work that is necessary to prevent transmission outages and minimize risk to the transmission system.

It should be noted that Requirement R1 is concerned with the content of the transmission vegetation management program and supporting documents, but does not address implementation of the elements of the transmission vegetation management program. Other requirements address implementation of the transmission vegetation management program. For example, sub-part 1.4 requires Transmission Owners to establish an imminent threat procedure. However, sub-part 1.4 does not address implementation or execution of the imminent threat procedure. This is addressed in Requirement R2. These situations will be reviewed in the following discussion.

Methodology to Control Vegetation

R1.1. *Specify the methodologies that the Transmission Owner uses to control vegetation*[2]

Transmission Owners are required to specify the methodologies or management methods used to control vegetation on applicable lines in the transmission vegetation management program. The methods specified in the transmission vegetation management program under this requirement are the methods that will be applied to the development and implementation of the annual work plan (R1.3 and R8).

The intent of this sub-part is for the Transmission Owner to list and generally describe the vegetation management methods that are used on its Active Transmission Line Right of Way. Transmission Owners are not required to deploy each of the methods listed in every situation. Nor are they required to provide a detailed description of each method, although these may exist in the Transmission Owner's specifications. Instead, the methods listed under this requirement are intended to provide a menu of vegetation management options that the Transmission Owner may deploy when developing and implementing the annual work plan based upon the many different circumstances that are typically encountered.

It should be emphasized that pruning is an ineffective maintenance method. Removal is always superior to pruning in ensuring tree conflicts do not occur.

In general, the best management practice for the Transmission Owner is to always exercise its maximum legal rights to achieve the objectives of the transmission vegetation management program. This minimizes the possibility of conflicts between energized conductors and vegetation. Since this is not always possible, the Transmission Owner's strategy should be to use its prescribed vegetation maintenance methods to work towards or achieve the maximum use of the Active Transmission Line Right of Way.

The following are several examples of how methodologies could be specified in the transmission vegetation management program under this requirement. These are offered as examples only and it is recognized that numerous other methodologies could be included in the transmission vegetation management program. It is also recognized that more detailed descriptions would typically be included in the Transmission Owner's internal specifications and procedures. The "average" tree does not usually cause a Sustained Outage. It is above-average growth that creates the greatest risk. In summary, methods must be applied in a sound biological manner

<u>Mechanical Clearing</u> — Remove all trees and brush in the Active Transmission Line Right of Way. Cut or mow all stumps to 3 inches or less above grade. De-limb and windrow on the edge of the right of way those larger trees that could be obstructive to other line maintenance activities.

<u>Selective Mechanical Tree Removal</u> — Selectively remove with chain saws or mechanized equipment all tall-growing species of trees, as listed in the specifications. Chemically treat the stumps of re-sprouting trees with the herbicide mixtures identified in the specification within one

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[2] *ANSI A300, Tree Care Operations — Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.*

hour of making the cut. All low-growing species of shrubs and trees, as listed in the specification, will be preserved unless otherwise noted.

<u>Low-Volume Foliar Selective Herbicide Treatment</u> — Selectively treat with herbicide <u>all</u> tall-growing species of trees as listed in the specification which are less than ten feet in height, using the low-volume foliar herbicide mixture and application process listed in the specification. All low-growing species of shrubs and trees, as listed in the specification will be preserved unless otherwise noted.

<u>Side Pruning</u> — Prune trees adjacent to the Active Transmission Line Right of Way that have grown to an extent that they have encroached upon or will soon encroach upon the clearances listed in the specification. In cases where specified clearances can not be achieved due to Active Transmission Line Right of Way width restrictions, remove branches to prevent entry into the Active Transmission Line Right of Way.

ANSI A300 – Best Management Practices for Tree Care Operations

Transmission Owners have the option of adopting the procedures and practices contained in an industry-recognized ANSI Standard known as A300 for use as a central component of its vegetation management program. The following is a description of A300.

Introduction

Integrated Vegetation Management (IVM) is a best management practice conveyed in the American National Standard for Tree Care Operations, Part 7 (ANSI 2006) and the International Society of Arboriculture's *Best Management Practices: Integrated Vegetation Management* (Miller 2007). IVM is consistent with the requirements in FAC-003-02, and it provides practitioners with what industry experts consider to be the most appropriate techniques to apply to electric right-of-way projects in order to exceed those requirements.

IVM is a system of managing plant communities whereby managers set objectives, identify compatible and incompatible vegetation, consider action thresholds, and evaluate, select and implement the most appropriate control method or methods to achieve set objectives. The choice of control method or methods should be based on the environmental impact and anticipated effectiveness, along with site characteristics, security, economics, current land use and other factors.

Planning and Implementation

Best management practices provide a systematic way of planning and implementing a vegetation management program. While designed primarily with transmission systems in mind, it is also applicable to distribution projects. As presented in ANSI A300 part 7 and the ISA best management practices, IVM consists of 6 elements:

1) Set Objectives
2) Evaluate the Site
3) Define Action Thresholds
4) Evaluate and Select Control Methods

5) Implement IVM
6) Monitor Treatment and Quality Assurance

The setting of objectives, defining action thresholds, and evaluating and selecting control methods all require decisions. The planning and implementation process is cyclical and continuous, because vegetation is dynamic and managers must have the flexibility to adjust their plans. Adjustments may be made at each stage as new information becomes available and circumstances evolve.

Set Objectives

Objectives should be clearly defined and documented. Examples of objectives can include promoting safety, preventing outages caused by vegetation growing into electric facilities and minimizing them from trees growing outside the right of way, maintaining regulatory compliance, protecting structures and security, restoring electric service during emergencies, maintaining access and clear lines of sight, protecting the environment, and facilitating cost effectiveness.

Objectives should be based on site factors, such as workload and vegetation type, in addition to human, equipment and financial resources. They will vary from utility to utility and project to project, depending on line voltage and criticality, as well as topographical, environmental, fiscal and political considerations. However, where it is appropriate, the overriding focus should be on environmentally-sound, cost effective control of species that potentially conflict with the electric facility, while promoting compatible, early successional, sustainable plant communities.

Work Load Evaluations

Work-load evaluations are inventories of vegetation that could have a bearing on management objectives. Work load assessments can capture a variety of vegetation characteristics, such as location, height, species, size and condition, hazard status, density and clearance from conductors. Assessments should be conducted considering voltage, conductor sag from ambient temperatures and loading, and the potential influence of wind on line sway.

Evaluations can be comprehensive or point sample, and can be done to obtain information on an entire program or an individual project. Comprehensive evaluations account for vegetation that could potentially affect management objectives, including hazard trees. Program-level comprehensive evaluations can be made of all target vegetation on a system, while project-level evaluations focus on vegetation relevant to a specific job. Comprehensive evaluations provide the advantage of supplying a complete set of data upon which to base management decisions. On the other hand, comprehensive surveys can be impractical for utilities with large numbers of trees, limited human and financial resources, or both.

Point sampling offers an alternative for utilities for which comprehensive inventories are impractical. Point sampling is cost effective, and has a proven track record for reasonable accuracy. A common method involves dividing a management area (a system or project) into equal-sized units and selecting a random sample sufficient to statistically represent the total work quantity. Random selection eliminates the chance of bias on the part of the investigator. Every plant or plant community of interest within each selected area is inventoried, with collected data used to forecast the total workload.

Evaluate and Select Control Methods

Control methods are the process through which managers achieve objectives. The most suitable control method best achieves management objectives at a particular site. Many cases call for a combination of methods. Managers have a variety of controls from which to choose, including manual, mechanical, herbicide and tree growth regulators, biological, and cultural options.

Manual Control Methods

Manual methods employ workers with hand-carried tools, including chainsaws, handsaws, pruning shears and other devices to control incompatible vegetation. The advantage of manual techniques is that they are selective and can be used where others may not be. On the other hand, manual techniques can be inefficient and expensive compared to other methods. If pruning is necessary, it should comply with ANSI A300 Part 1 (ANSI 2001) and ISA best management practices for utility pruning (Kempter 2004).

Mechanical Control Methods

Mechanical controls are done with machines. They are efficient and cost effective, particularly for clearing dense vegetation during initial establishment, or reclaiming neglected or overgrown right of way. On the other hand, mechanical control methods can be non-selective and disturb sensitive sites.

Tree Growth Regulator and Herbicide Control Methods

Tree growth regulators and herbicides are essential for effective vegetation management. Tree growth regulators (TGRs) are designed to reduce growth rates by interfering with natural plant processes. TGRs can be helpful where removals are prohibited or impractical by reducing the growth rates of some fast-growing species.

Herbicides control plants by interfering with specific botanical biochemical pathways. Herbicide use can control individual plants that are prone to re-sprout or sucker after removal. When trees that re-sprout or sucker are removed without herbicide treatment, dense thickets develop, impeding access, swelling workloads, increasing costs, blocking lines-of-site, and deteriorating wildlife habitat. Treating suckering plants allows early successional, compatible species to dominate the right-of-way and out-compete incompatible species, ultimately reducing work.

Cultural Control Methods

Cultural methods modify habitat to discourage incompatible vegetation and establish and manage desirable, early successional plant communities. Cultural methods take advantage of seed banks of native, compatible species lying dormant on site. In the long run, cultural control is the most desirable method where it is applicable.

A cultural control known as cover-type conversion provides a competitive advantage to short-growing, early successional plants, allowing them to thrive and eventually out-compete unwanted tree species for sunlight, essential elements and water. The early successional plant community is relatively stable, tree-resistant and reduces the amount of work, including herbicide application, with each successive treatment.

Wire-Border Zone

The wire-border zone technique is a management philosophy that can be applied through cultural control. W.C. Bramble and W.R. Byrnes developed it in the mid-1980s out of research begun in 1952 on a transmission right-of-way in the Pennsylvania State Game Lands 33 Research and Demonstration project (Yahner and Hutnik (2004).

The wire zone is the section of a utility transmission right-of-way directly under the wires and extending outward about 10 feet on each side. The wire zone is managed to promote a low-growing plant community dominated by grasses, herbs and small shrubs (under 3 feet in height at maturity). The border zone is the remainder of the right-of-way. It is managed to establish small trees and tall shrubs (under 25 feet in height at maturity). When properly managed, diverse, tree-resistant plant communities develop in wire and border zones. The communities not only protect the electric facility and reduce long-term maintenance, but also enhance wildlife habitat, forest ecology and aesthetic values.

Although the wire-border zone is a best practice in many instances, it is not necessarily universally suitable. For example, standard wire-border zone prescriptions may be unnecessary where lines are high off the ground, such as across low valleys or canyons, so the technique can be modified without sacrificing reliability.

One way to accommodate variances in topography is to establish different regions based on wire height. For example, over canyon bottoms or other areas where conductors are 100 feet or more above the ground, only a few trees are likely to be tall enough to conflict with the lines. In those cases, trees that potentially interfere with the transmission lines can be removed selectively on a case-by-case basis.

In areas where the wire is lower, perhaps between 50-100 feet from the ground, a border zone community can be developed throughout the right-of-way. Note that in many cases, conductor attachment points are more than 50 feet off the ground, so a border zone community can be cultivated near structures. Where the line is less than 50 feet off the ground, managers could apply a full wire-border zone prescription.

An environmental advantage of this type of modification is stream protection. Streams often course through the valleys and canyons where lines are likely to be elevated. Leaving timber or border zone communities in canyon bottoms helps shelter this valuable habitat, enabling managers to achieve environmentally sensitive objectives.

Implement IVM

All laws and regulations governing IVM practices and specifications written by qualified vegetation managers must be followed. Integrated vegetation management control methods should be implemented on regular work schedules, which are based on established objectives and completed assessments. Work should progress systematically, using control measures determined to be best for varying conditions at specific locations along a right-of-way. Some considerations used in developing schedules include the importance and type of line, vegetation clearances, work loads, growth rate of predominant vegetation, geography, accessibility, and in some cases, time lapsed since the last scheduled work.

Clearances Following Work

The Transmission Owner should establish and document appropriate minimum clearance distances to be achieved at the time of work. Clearances following work should be sufficient to meet management objectives, including reducing preventing trees from entering the Critical Clearance Zone, electric safety risks, service-reliability threats and cost.

Monitor Treatment and Quality Assurance

An effective program includes documented processes to evaluate results. Evaluations can involve quality assurance while work is underway and after it is completed. Monitoring for quality assurance should begin early to correct any possible miscommunication or misunderstanding on the part of crewmembers. Early and consistent observation and evaluation also provides an opportunity to modify the plan, if need be, in time for a successful outcome.

Utility vegetation management programs should have systems and procedures in place for documenting and verifying that vegetation management work was completed to specifications. Post-control reviews can be comprehensive or based on a statistically representative sample. This final review points back to the first step and the planning process begins again.

Summary

Integrated vegetation management offers a systematic way of planning and implementing a vegetation management program as presented in ANSI A300 Part 7. This methodology enables a program to comply with the NERC *Transmission Vegetation Management Program* standard (FAC-003-2). Managers should select control options to best promote management objectives. Tree-resistant plant communities can be a desirable objective to reduce long-term work loads and costs because, once established, they out-compete incompatible plants. When effectively implemented, IVM is a systematic, preventive strategy that results in site-specific treatments to meet management objectives. A sound program includes documented processes to evaluate results, which should involve both monitoring for quality assurance while work is underway and after it is completed. However, the overriding focus should be on environmentally-sound, cost effective control of species that potentially conflict with the electric facility while promoting compatible, early successional, sustainable plant communities where appropriate.

Vegetation Inspection Frequency

R1.2. *Specify a vegetation inspection frequency of at least once per calendar year that takes into account local* [3] *and environmental factors.*

The transmission vegetation management program shall specify the frequency of inspection. The inspection frequency shall be at least once per calendar year. Transmission Owners should consider factors that could warrant more frequent inspection including growth studies, the need to insure individual fast-growing trees have not encroached into the Critical Clearance Zone, the need to identify excessive spring growth, and the need to identify seasonally occurring hazard trees.

[3] Local factors include treatment cycle, extent and type of treatment, and their relationship to the normal growth rate.

Annual Plans

R1.3. *Require an annual plan that identifies the applicable lines to be maintained and work to be performed during the year. It shall be flexible to adjust to changing conditions and to findings from vegetation inspections. Adjustments to the plan within the year are permissible. The plan shall take into consideration permitting and scheduling requirements from landowners or regulatory authorities. It shall support the objectives of the transmission vegetation management program and use the methodologies outlined in the transmission vegetation management program.*

The work plan is not intended to be a “span-by-span” detailed description of all work to be performed. It is intended to require the Transmission Owner to plan and schedule vegetation work to avoid encroachment into the Critical Clearance Zone.

The reference in the standard to "implement the annual work plan for vegetation management to accomplish the purpose of this standard within the extent of its easement and/or legal rights" is intended to address the importance of maintaining all locations on the Active Transmission Line Right of Way for reliability purposes in lieu of making special exceptions.

- Property owners and other interested parties occasionally request special considerations to leave undesirable vegetation conditions. It is recognized that such considerations must never be allowed to impact reliability.
- These undesirable vegetation conditions require more frequent work or inspections than other locations with similar vegetation threats and similar easement rights which are not subject to the special property requests
- The Transmission Owner's vegetation maintenance work necessary to implement the annual work plan is most effective when performed to the maximum extent allowed by any legal and/or easement rights.
- The Transmission Owner should, therefore, endeavor to maintain its Active Transmission Line Right of Way to the full extent of its legal rights at all times and in all cases.

This approach is superior to incremental management over the long term because it reduces overall encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient at all locations on the Active Transmission Line Right of Way .

Imminent Threat Procedure

> ***R1.4.*** *Require a process or procedure for response to imminent threats of a vegetation related Sustained Outage. The process or procedure shall specify actions which shall include immediate communication of the threat to the Transmission Operator, and may include actions such as a temporary reduction in line Rating, switching lines out of service, or other actions.*

The term "imminent threat" refers to a vegetation condition which is placing the transmission line at a significant risk of a Sustained Outage.

Examples of imminent threats may include vegetation that is rapidly approaching or has encroached within the Critical Clearance Zone or a tall tree which has been uprooted and is leaning precariously toward transmission conductors which could draw an arc when the tree falls. Both cases represent imminent threats due to the high probability that they could cause a Sustained Outage.

Two key elements of an acceptable imminent threat procedure are outlined below:

- Upon discovery of an imminent threat, the operating authority (operating authority refers to personnel with direct responsibility for operating the transmission lines, including but not limited to ordering the de-rating or de-energization of transmission lines) will be notified of the condition so that action (such as temporary reduction in line Rating, switching the line out of service, etc.) may be taken until the threat is relieved.
- The protocol for contacting the operating authority should be defined. For example, some Transmission Owners' processes may require a call directly to the operating authority, while other Transmission Owners may require a call to a supervisor or field forester. The process should be explicit for the expectations of actions upon the individual discovering the imminent threat.

The urgency of addressing imminent threats may be contrasted with the longer time frames of corrective action plans which are developed from a corrective action process as defined in R1.5. The communication of imminent threats should typically be done in a matter of minutes or hours, whereas corrective action plans may require months or years (see requirement R1.5).

All serious conditions are not necessarily considered as imminent threats under the Standard. For example, Transmission Owners may assign a high priority to the removal of trees that have been designated for removal under a danger tree identification program, but not yet encroached within the Critical Clearance Zone. These trees are not considered imminent threats under the Standard because there is not a high probability that they will grow sufficiently before treatment to encroach into the Critical Clearance Zone or immediately fall and subsequently cause a Sustained Outage.

Some encroachments may be found within the Critical Clearance Zone at a time when there exists sufficient safety clearance distance from the conductors to allow their safe removal. If so their removal may not require switching the line out of service, de-rating the line temporarily or other actions.

Interim Corrective Action Process

> ***R1.5.*** *Specify an interim corrective action process for use when the Transmission Owner is constrained from performing vegetation maintenance as planned.*

Each Transmission Owner is required to specify an interim corrective action process in its transmission vegetation management program. The purpose of this sub-part is to ensure that Transmission Owners have in place a process to develop a corrective action plan that identifies and mitigates risk to the reliability of transmission lines when the Transmission Owner is constrained from performing vegetation maintenance work as planned.

Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the Transmission Owner's rights, or other circumstances. The Standard recognizes that numerous circumstances resulting in work constraints can occur, and that numerous ways to identify and mitigate the associated risks to line reliability can be developed. Thus, the requirement is such that the Transmission Owner must specify a general, flexible corrective action process which provides a framework that can be applied over a wide range of situations to ensure line reliability.

A general interim corrective action process may include the following steps:

- Determine and understand the constraint
- Determine the degree of risk to line reliability due to the constraint
- Determine a specific interim corrective action plan to mitigate the risk
- If applicable, determine the time frame for the corrective action plan to be in effect

Implement Imminent Threat Procedure

R2. *Each Transmission Owner shall implement its imminent threat procedure when the Transmission Owner has knowledge, obtained through normal operating practices or notification from others, that the Critical Clearance Zone is approached by vegetation to prevent an encroachment of the Critical Clearance Zone.*

Determining Clearance Distances for Vegetation near Transmission Lines

A vital component of an effective vegetation management program is maintaining an adequate distance between energized transmission line conductors and vegetation. Maintaining a minimum separation can prevent inadvertent Sustained Outages caused by direct contact of the conductors and the vegetation or sparkover between the conductors and the vegetation.

The Gallet Equation is a well known method of computing the required strike distance for proper insulation coordination, and has the ability to take into account various air gap geometries, as well as non-standard atmospheric conditions. When the Gallet Equation and conservative probabilistic methods are combined, i.e. deterministic design, sparkover probabilities of 10^{-6} or less are achieved. This approach is well known for its conservatism and was used to design the first 500 kV and 765 kV lines in North America [1]. Thus, the deterministic design approach using the Gallet Equation is used for the standard to compute the minimum strike distance between transmission lines and the vegetation that may be present in or along the transmission corridor.

Method Explanation (Gallet Equation)

In 1975 G. Gallet published a benchmark paper that provided a method to compute the critical flashover voltage (CFO) of various air gap geometries [4]. The Gallet Equation uses various “gap factors” to take into account various air gap geometries. Various gap factor values are provided in [1]. If the vegetation in a transmission corridor, e.g. a tree, is assumed electrically to be a large structure then the CFO of such an air gap geometry can be computed for dry or wet conditions using a well established equation proposed by Gallet [1],[2],[4],

$$CFO_A = k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} \qquad (1)$$

where,

k_w is defined as the factor that takes into account wet or dry conditions (dry = 1.0 and wet = 0.96) and phase arrangement (multiply by 1.08 for outside phase), e.g. outside phase and wet conditions = (0.96)(1.08) = 1.037,

k_g is defined as the gap factor (1.3 for conductor to large structure),

D	is the strike distance (m),
CFO_A	is the CFO for the relative air density (kV).
δ	is defined as the relative air density and is approximately equal to (2) where A is the altitude in km,

$$\delta = e^{-\frac{A}{8.6}} \tag{2}$$

$$m = 1.25G_0\left(G_0 - 0.2\right) \tag{3}$$

$$G_0 = \frac{CFO_s}{500 \cdot D} \tag{4}$$

$$CFO_s = k_w \cdot k_g \cdot \frac{3400}{1 + \frac{8}{D}} \tag{5}$$

where CFO_S is the CFO for standard atmospheric conditions (kV). Using (1)-(5), the required CFO_A can be computed using an iterative process.

Once the CFO_A is known, deterministic methods can be used to determine the required clearance distance. If we let the maximum switching overvoltage be equal to the withstand voltage of the air gap (CFO_A - 3σ) then the CFO_A can be written as (6).

$$CFO_A = \frac{V_m}{1 - 3\left(\frac{\sigma}{CFO_A}\right)} \tag{6}$$

where

V_m is equal to the maximum switching overvoltage, i.e. the value that has a 0.135% chance of being exceeded,

σ is the standard deviation of the air gap insulation,

CFO_A is the critical flashover voltage of the air gap insulation under non-standard atmospheric conditions.

The ratio of σ to the CFO_A given in (6) can be assumed to be 0.05 (5%) [1]. Thus, (6) can be written as (7).

$$CFO_A = \frac{V_m}{0.85} \tag{7}$$

Substituting (7) into (1) we arrive at (8).

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1 + \frac{8}{D}} \tag{8}$$

Equation 8 relates the maximum transient overvoltage, V_m, to the air gap distance, D. Using (8) to compute the required clearance distance for the specified air gap geometry (conductor to large structure) results in a probability of flashover in the range of 10^{-6}.

Transient Overvoltage

In general, the worst case transient overvoltages occurring on a transmission line are caused by energizing or re-energizing the line with the latter being the extreme case if trapped charge is present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to sparkover from the line conductor to nearby vegetation. Thus, the worst case scenarios that are typically analyzed for insulation coordination purposes (e.g. line energization and re-energization) can be ignored. For the purposes of FAC-003-2, the worst case transient overvoltage then becomes the maximum value that can occur with the line energized. Determining a realistic value of transient overvoltage for this situation is difficult because the maximum transient overvoltage factors listed in the literature are based on a switching operation of the line in question. In other words, these maximum overvoltage values (e.g. the values listed in [2], [3] and [5]) are based on the assumption that the subject line is being energized, re-energized or de-energized. These operations, by their very nature, will create the largest transient overvoltages. Typical values of transient overvoltages of in-service lines, as such, are not readily available in the literature because the resulting level of overvoltage is negligible compared with the maximum (e.g. re-energizing a transmission line with trapped charge). A conservative value for the maximum transient overvoltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 p.u.[2]. This value is a conservative estimate of the transient overvoltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without a pre-insertion device (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. 362 kV), the maximum transient overvoltage of an “in-service” ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 p.u. or less [2]. It is well known that these theoretical transient overvoltages will not be experienced at locations remote from the bus at which they were created; however, in order to be conservative, it will be assumed that all nearby ac lines are subjected to this same level of overvoltage. Thus, a maximum transient overvoltage factor of 2.0 p.u. for 242 kV and below and 1.4 p.u. for ac transmission lines 362 kV and above is used to compute the required clearance distances for vegetation management purposes.

The overvoltage characteristics of dc transmission lines vary somewhat from their ac counterparts. The referenced empirically derived transient overvoltage factor used to calculate the minimum clearance distances from dc transmission lines to vegetation for the purpose of FAC-003-2 will be 1.8 p.u.[3].

Example Calculation

An example calculation is presented below using the proposed method of computing the vegetation clearance distances. It is assumed that the line in question has a maximum operating voltage of 550 kV_{rms} line-to-line. Using a per unit transient overvoltage factor of 1.4, the result is a peak transient voltage of 629 kV_{crest}. It is further assumed that the line in question operates at a maximum altitude of 7000 feet (2.134 km) above sea level.

The required withstand voltage of the air gap must be equal to or greater than 629 kV_{crest}. Since the altitude is above sea level, (1) - (5) have to be iterated on to achieve the desired result. Equation (9) can be used as an initial guess for the clearance distance.

$$D_i = \frac{8}{\dfrac{3400 \cdot k_w \cdot k_g}{\left(\dfrac{V_m}{0.85}\right)} - 1} \tag{9}$$

For our case here, V_m is equal to 629 kV, k_w = 1.037 and k_g = 1.3. Thus,

$$D_i = \frac{8}{\dfrac{3400 \cdot k_w \cdot k_g}{\left(\dfrac{V_m}{0.85}\right)} - 1} = \frac{8}{\dfrac{3400 \cdot 1.037 \cdot 1.3}{\left(\dfrac{629}{0.85}\right)} - 1} = 1.535m \tag{10}$$

Using (2)-(5) and (8) the withstand voltage of the air gap is next computed. This value will then be compared to the maximum transient overvoltage.

$$CFO_S = k_w \cdot k_g \cdot \frac{3400}{1 + \dfrac{8}{D}} = 1.037 \cdot 1.3 \cdot \frac{3400}{1 + \dfrac{8}{1.535}} = 737.7kV \tag{11}$$

$$\delta = e^{-\frac{A}{8.6}} = e^{-\frac{2.134}{8.6}} = 0.78 \tag{12}$$

$$G_O = \frac{CFO_S}{500 \cdot D} = \frac{737.7}{(500) \cdot (1.535)} = 0.961 \tag{13}$$

$$m = 1.25 \cdot G_O (G_O - 0.2) = 1.25 \cdot 0.961(0.961 - 0.2) = 0.915 \tag{14}$$

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1 + \dfrac{8}{D}} = (0.85)(1.037)(1.3)(0.78)^{0.915} \left(\frac{3400}{1 + \dfrac{8}{1.535}} \right) = 499.8kV \tag{15}$$

The calculated V_m is less than 629 kV; thus, the clearance distance must be increased. A few iterations using (2)-(5) and (8) are required until the computed $V_m \geq$ 629 kV. For this case it was found that D = 1.978 m (6.49 feet) yielded V_m = 629.3 kV. Using this clearance distance the following values were computed for the final iteration.

$$CFO_S = k_w \cdot k_g \cdot \frac{3400}{1 + \dfrac{8}{D}} = 1.037 \cdot 1.3 \cdot \frac{3400}{1 + \dfrac{8}{1.978}} = 908.5kV \tag{16}$$

$$\delta = e^{-\frac{A}{8.6}} = e^{-\frac{2.134}{8.6}} = 0.78 \tag{17}$$

$$G_O = \frac{CFO_S}{500 \cdot D} = \frac{908.5}{(500)\cdot(1.978)} = 0.919 \tag{18}$$

$$m = 1.25 \cdot G_O(G_O - 0.2) = 1.25 \cdot 0.919(0.919 - 0.2) = 0.825 \tag{19}$$

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} = (0.85)(1.037)(1.3)(0.78)^{0.825}\left(\frac{3400}{1+\frac{8}{1.978}}\right) = 629.3kV \tag{20}$$

Therefore, the minimum vegetation clearance distance for a maximum line to line ac operating voltage of 550 kV at 7000 feet above sea level is 1.978 m (6.49 feet). Table I provides calculated distances for various altitudes and maximum system operating ac voltages.

TABLE I — Minimum Vegetation Clearance Distances
For Alternating Current Voltages

(AC) Nominal System Voltage (kV)	**(AC) Maximum System Voltage (kV)**	**D feet (meters) sea level**	**D feet (meters) 3,000ft (914.4m)**	**D feet (meters) 4,000ft (1219.2m)**	**D feet (meters) 5,000ft (1524m)**	**D feet (meters) 6,000ft (1828.8m)**
765	800	8.06ft (2.46m)	8.89ft (2.71m)	9.17ft (2.80m)	9.45ft (2.88m)	9.73ft (2.97m)
500	550	5.06ft (1.54m)	5.66ft (1.73m)	5.86ft (1.79m)	6.07ft (1.85m)	6.28ft (1.91m)
345	362	3.12ft (0.95m)	3.53ft (1.08m)	3.67ft (1.12m)	3.82ft (1.16m)	3.97ft (1.21m)
230	242	2.97ft (0.91m)	3.36ft (1.02m)	3.49ft (1.06m)	3.63ft (1.11m)	3.78ft (1.15m)
161*	169	2ft (0.61m)	2.28ft (0.69m)	2.38ft (0.73m)	2.48ft (0.76m)	2.58ft (0.79m)
138*	145	1.7ft (0.52m)	1.94ft (0.59m)	2.03ft (0.62m)	2.12ft (0.65m)	2.21ft (0.67m)
115*	121	1.41ft (0.43m)	1.61ft (0.49m)	1.68ft (0.51m)	1.75ft (0.53m)	1.83ft (0.56m)
88*	100	1.15ft (0.35m)	1.32ft (0.40m)	1.38ft (0.42m)	1.44ft (0.44m)	1.5ft (0.46m)
69*	72	0.82ft (0.25m)	0.94ft (0.29m)	0.99ft (0.30m)	1.03ft (0.31m)	1.08ft (0.33m)

*As designated by the Reliability Coordinator

TABLE I — Minimum Vegetation Clearance Distances (D)
For Alternating Current Voltages

(AC) Nominal System Voltage (kV)	(AC) Maximum System Voltage (kV)	D feet (meters) 7,000ft (2133.6m)	D feet (meters) 8,000ft (2438.4m)	D feet (meters) 9,000ft (2743.2m)	D feet (meters) 10,000ft (3048m)	D feet (meters) 11,000ft (3352.8m)
765	800	10.01ft (3.05m)	10.29ft (3.14m)	10.57ft (3.22m)	10.85ft (3.31m)	11.13ft (3.39m)
500	550	6.49ft (1.98m)	6.7ft (2.04m)	6.92ft (2.11m)	7.13ft (2.17m)	7.35ft (2.24m)
345	362	4.12ft (1.26m)	4.27ft (1.30m)	4.43ft (1.35m)	4.58ft (1.40m)	4.74ft (1.44m)
230	242	3.92ft (1.19m)	4.07ft (1.24m)	4.22ft (1.29m)	4.37ft (1.33m)	4.53ft (1.38m)
161*	169	2.69ft (0.82m)	2.8ft (0.85m)	2.91ft (0.89m)	3.03ft (0.92m)	3.14ft (0.96m)
138*	145	2.3ft (0.70m)	2.4ft (0.73m)	2.49ft (0.76m)	2.59ft (0.79m)	2.7ft (0.82m)
115*	121	1.91ft (0.58m)	1.99ft (0.61m)	2.07ft (0.63m)	2.16ft (0.66m)	2.25ft (0.69m)
88*	100	1.57ft (0.48m)	1.64ft (0.50m)	1.71ft (0.52m)	1.78ft (0.54m)	1.86ft (0.57m)
69*	72	1.13ft (0.34m)	1.18ft (0.36m)	1.23ft (0.37m)	1.28ft (0.39m)	1.34ft (0.41m)

*As designated by the Reliability Coordinator

Likewise, a minimum clearance distance table for high voltage direct current lines may be derived using alternating current methods [7]. Table I is expanded below to provide calculated distances for various altitudes and system operating voltages.

TABLE I — Minimum Vegetation Clearance Distances (D)
For Direct Current Voltages

(DC) Pole to Pole Nominal Voltage (kV)	**D feet (meters) sea level**	**D feet (meters) 3,000ft (914.4m) Alt.**	**D feet (meters) 4,000ft (1219.2m) Alt.**	**D feet (meters) 5,000ft (1524m) Alt.**	**D feet (meters) 6,000ft (1828.8m) Alt.**
1500	13.92ft (4.24m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)
1200	10.07ft (3.07m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)
1000	7.89ft (2.40m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)
800	4.78ft (1.46m)	5.35ft (1.63m)	5.55ft (1.69m)	5.75ft (1.75m)	5.95ft (1.81m)
500	3.43ft (1.05m)	4.02ft (1.23m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)

Pole to Pole Nominal Voltage (kV)	**D feet (meters) 7,000ft (2133.6m) Alt.**	**D feet (meters) (8,000ft (2438.4m) Alt.**	**D feet (meters) 9,000ft (2743.2m) Alt.**	**D feet (meters) 10,000ft (3048m) Alt.**	**D feet (meters) 11,000ft (3352.8m) Alt.**
1500	16.55ft (5.04m)	16.9ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
1200	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	(13.54ft 4.13m)
1000	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
800	6.15ft (1.87m)	6.36ft (1.94m)	6.57ft (2.00m)	6.77ft (2.06m)	6.98ft (2.13m)
500	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5ft (1.52m)	5.17ft (1.58m)

Critical Clearance Zone

The best management practice for the Transmission Owner is to always exercise its maximum legal rights with regards to Active Transmission Line Right of Way vegetation clearing work. Doing so minimizes the possibility of incurring any conflicts between energized conductors and vegetation. Since this is not always possible, Table I in FAC-003-2 identifies the minimum radial distances, derived using the Gallet equations, which are required to prevent a flashover (sparkover) at the corresponding line voltage ratings.

The minimum radial distance values in Table I represent a radial zone (or shell) around a conductor within which there is a high probability that a flashover event will occur. However, the minimum radial distance concept should not be mistaken to suggest that a static condition is being managed; in fact, the reality is a very dynamic situation. The use of the Critical Clearance Zone concept as set forth by the Standard attempts to simplify and address this complex dynamic management requirement to aid in field applications.

The conductor's position in space at any point in time is continuously changing as a reaction to a number of different loading variables affecting the conductor's movement within each line span. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and swing by combining physical factors such as ice and wind loading.

As a consequence of these loading variables, the conductor's position in space is dynamic and continuously moving. Over some period of time, the conductor will ultimately pass through all possible positions it can occupy in space. This full range of positions can be thought of as the conductor's "flight path".

As the conductor moves throughout its flight path, the minimum clearance shell surrounding the conductor obviously moves with it. Therefore, this shell also maps out an area in space called the "Critical Clearance Zone". Any conductive item (such as a tree) that has encroached within this Critical Clearance Zone has the potential to cause flashover when the conductor enters a corresponding location in its flight path.

The shape and size of the Critical Clearance Zone around the conductor is irregular and will change depending on where a conductor segment is located within the span. At mid-span, where the potential for conductor movement is the greatest due to sag and wind deflection, the corresponding Critical Clearance Zone is also the largest and most irregular. Conversely, the Critical Clearance Zone is at its smallest near the conductor attachment to the transmission line structure insulator assembly. In the most extreme case, the Critical Clearance Zone again becomes a simple radial circle at a rigidly fixed insulator attachment point such as with a V-string or standoff insulator type of installation. Figures 4 through 7 below demonstrate these concepts.

With the size, shape and area of the Critical Clearance Zone dramatically changing as one progresses along a span, identifying the precise location and boundary of the Critical Clearance Zone around the conductor in the field becomes very problematic. First, all the variables involved make it very complicated and difficult to calculate the exact shape and size of the Critical Clearance Zone at any particular location in any one, and ultimately all, of the many spans of a transmission line. Second, at the time of field measurement, it is very difficult to precisely know where the conductor is within its wide range of all possible flight path positions.

Therefore, even if the exact size and shape of the Critical Clearance Zone is known, it becomes nearly impossible to field correlate and accurately "superimpose" the Critical Clearance Zone around the conductor.

There are also operational adjustments that must be made to the Critical Clearance Zone as well when managing vegetation. When transmission lines are initially designed, basic engineering assumptions and calculations are made with regard to the maximum environmental and physical forces to which the facility will be exposed as well as anticipated electrical loads. Again, these assumptions include the consideration of things like the maximum wind and ice loading, thermal heating and dissipation, span lengths, conductor strength, associated stringing and sagging conditions, etc. All of these design considerations are combined to define the anticipated "design flight path" for the conductor within each span. However, transmission facilities are not always available to be operated at their full Rating for numerous reasons. For example, transmission facilities can sometimes be built to a higher design voltage than they are currently operated at to reserve capacity that will be utilized with other future system upgrades. Consequently in cases such as these that do not subject a facility to its maximum design capacity, the "operational flight path" of the conductor can be anticipated to be somewhat smaller than the full range of the "designed flight path". Subsequent decisions regarding vegetation management, therefore, need only be made with regard to ensuring the integrity of the actual anticipated operational flight path for the conductor.

Given all of the complicated considerations outlined above, vegetation management around near the Critical Clearance Zone can be very challenging. It is important that the full conductor flight path, within the appropriate limits defined by the lesser of the design parameters or the operational constraints for the line, be available at all times to accommodate the full range of power system operational requirements. Even with the best planning and execution of the vegetation management program, including the use of frequent inspections, vegetation can still unintentionally approach or even encroach into the Critical Clearance Zone without a Transmission Owner's immediate awareness. Such an event does not always result in a flashover if the conductor is not simultaneously occupying that same area of the Critical Clearance Zone. An example of this would be when the conductor is not currently being blown to the extreme edge of its designed flight path from a maximum anticipated wind loading event. However, in such a case it is imperative - and required by the Standard - that the Transmission Owner's Imminent Threat process be implemented immediately upon discovery to correct the approaching or encroaching situation. Failure to do so is a violation of Requirement R2 of the standard.

An accurate representation of the Critical Clearance Zone in the field, correctly positioned around the conductor, is critically important if the Critical Clearance Zone is to be used as an essential parameter for vegetation management and Standards regulation. Because of all of the variables and difficulties in determining the Critical Clearance Zone, as well as the consequences associated with Requirement R4 for failure to maintain Critical Clearance Zone clearances, it is anticipated and expected that Transmission Owners will manage vegetation at distances greater than the Critical Clearance Zone. Given the variation of the Critical Clearance Zone's size and shape at various locations along the line span, it is anticipated that many Transmission Owners will establish a work trigger well outside the Critical Clearance Zone.

Further, to ensure adequate field monitoring and detection of incompatible vegetation conditions, Standard FAC 003-2 requires inspections on a frequency that is appropriate to verify and ensure there are no undiscovered Critical Clearance Zone approaches or encroachments. The anticipated growth rates of the vegetation surveyed in relationship to its speed of approach and distance from the Critical Clearance Zone is a very important consideration during inspection. At a minimum, the inspection frequency can not be less than once per year.

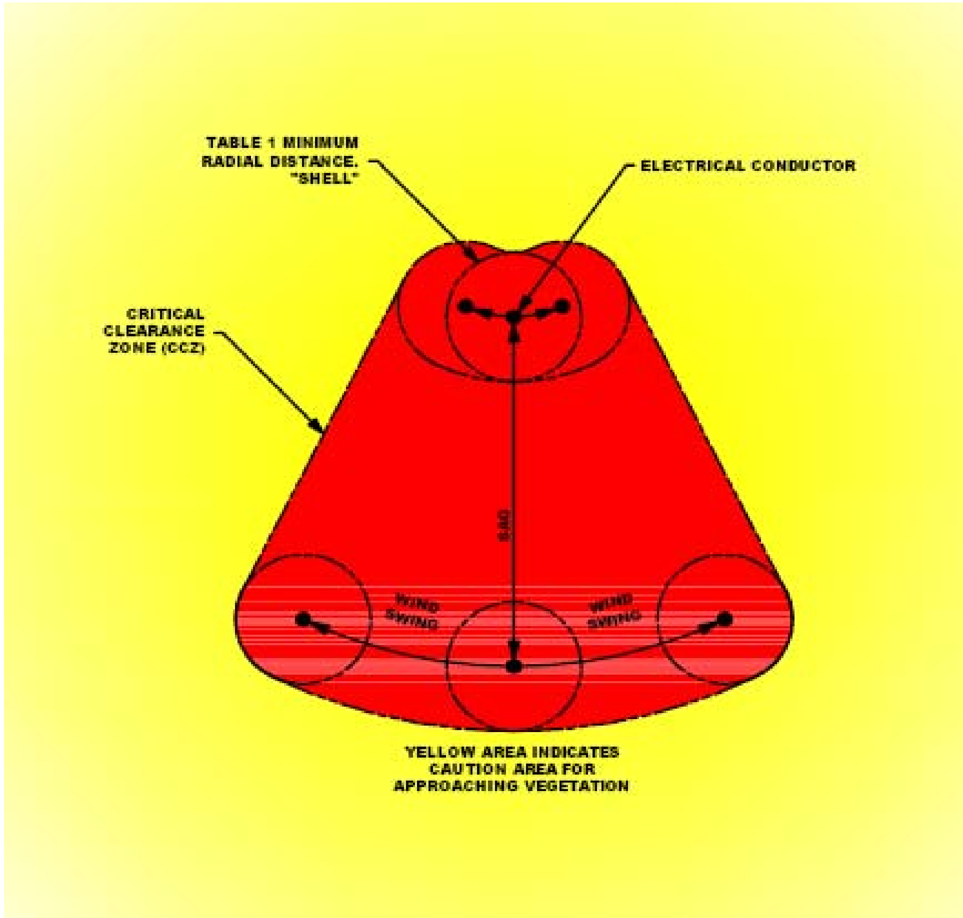

Figure 4

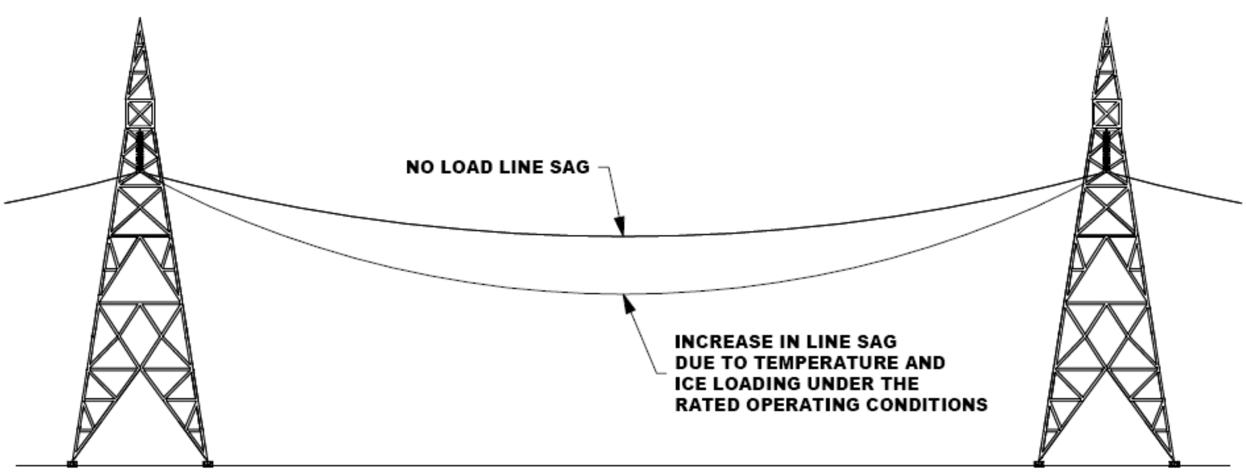

Figure 5

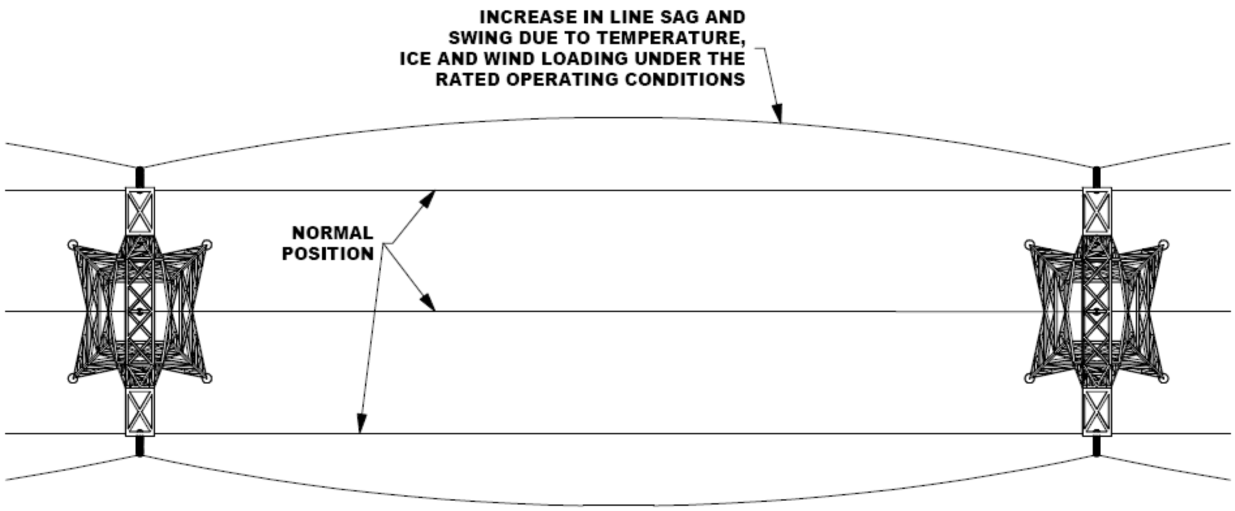

Figure 6

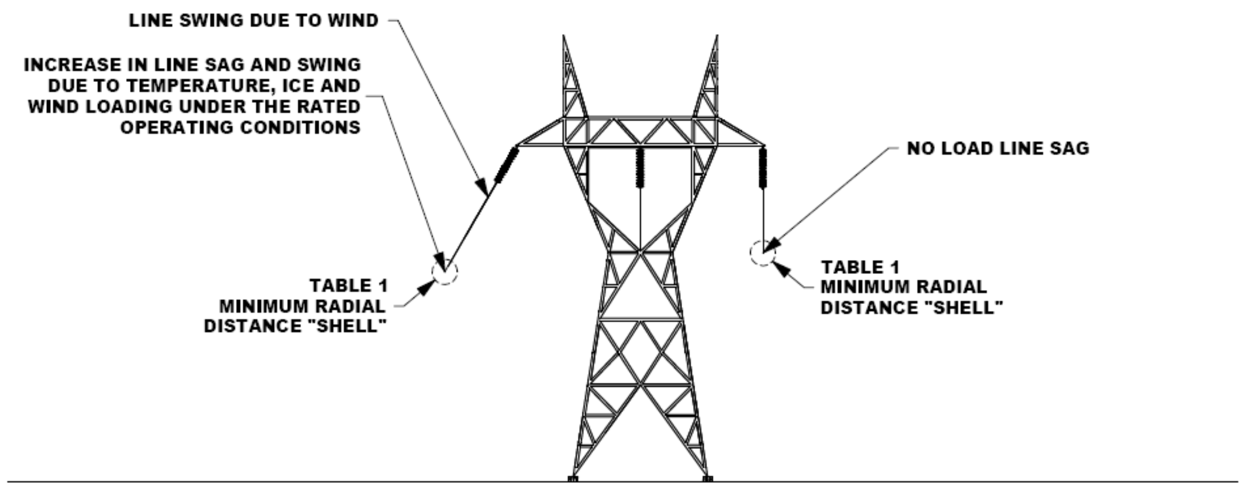

Figure 7

Conduct Vegetation Inspections

R3. *Each Transmission Owner shall conduct inspections of all applicable lines in accordance with the frequency specified in its transmission vegetation management program.*

The Requirement is self explanatory and no additional information is necessary.

Encroachments within Critical Clearance Zone

R4. *Each Transmission Owner shall prevent encroachments within the Critical Clearance Zone of its applicable transmission lines with the following exceptions:*
1. Encroachments of the Critical Clearance Zone that result from natural disasters[4]
2. Encroachments of the Critical Clearance Zone that result from human or animal activity[5]

The presence of vegetation in the Critical Clearance Zone presents a state of reduced transmission system reliability and is a violation of Requirement R4. A Critical Clearance Zone encroachment incident is defined as the presence in the Critical Clearance Zone of vegetation from a single tree, or a group of trees or vegetation in a single span or adjacent spans. The exposure to Critical Clearance Zone encroachment incidents varies widely among transmission systems owned by large and small Transmission Owners.

[4] Examples include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods.

[5]Examples include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation.

Sustained Outages— Vegetation Growth

> ***R5.*** *Each Transmission Owner shall prevent Sustained Outages of applicable lines*[6] *due to vegetation growing into a conductor operating between no load and its Rating with the following exceptions:*
>
> 1. *Sustained Outages of applicable lines that result from natural disasters.*
> 2. *Sustained Outages of applicable lines that result from human or animal activity.*

The most significant vegetation related reliability risk to the transmission system involves Sustained Outages due to vegetation growing into transmission lines. This is commonly referred to as a grow-in or sag-in. These events could lead to widespread cascading failures, such as the August 10, 1996 West Coast Blackout and the August 14, 2003 US-Canada blackout.

These blackouts occurred during the summer months when the transmission system is more vulnerable to cascading events which can lead to blackouts. A review of NERC disturbance reports related to blackouts indicates that most major blackouts attributed to vegetation were caused by grow-in or sag-in events during the summer.

Since grow-in events have historically resulted in several major blackouts the standard recognizes that they present a high risk to the system. Sustained Outages due to sag-ins that occur due to natural disasters are beyond the control of the Transmission Owner. In addition it is often not possible in the aftermath of a natural disaster to do the forensics to determine what happened. Therefore such outages are not considered violations of this requirement.

Sustained Outages due to sag-ins that occur due to human (such as new plantings of tall vegetation, automobile collisions into towers) or animal activity are beyond the control of the Transmission Owner. Therefore such Sustained Outages are not considered violations of this requirement.

The standard recognizes that multiple Sustained Outages on an individual line can be caused by the same vegetation. As such, the Standard recognizes these events as a single Sustained Outage. For example a Sustained Outage could be caused by a tree but be mistakenly attributed to something else (e.g. contaminated insulator string or a different tree). After that situation is addressed the line would be re-energized and would suffer another Sustained Outage from contact with the tree.

Investigations are often hampered by weather conditions, darkness and/or other factors that lead to a misdiagnosis of the cause of the fault as noted in the above example.

[6] Multiple Sustained Outages on an individual line, if caused by the same vegetation, shall be considered as one outage regardless of the actual number of outages within a 24-hour period.

Sustained Outages— Blowing Vegetation

R6. *Each Transmission Owner shall prevent Sustained Outages of applicable lines[6] due to the blowing together of vegetation and a conductor with Active Transmission Line Right of Way (operating within design blow-out conditions) with the following exception:*

1. *Sustained Outages of applicable lines that result from sustained winds or gusts due to natural [4]*

[4]

Unlike grow-ins which are addressed in Requirement R5, a review of NERC disturbance reports related to blackouts indicates major blackouts were rarely if ever attributed to vegetation-related Sustained Outages due to blowing together of vegetation and transmission conductors. These events are known as blow-ins.

The standard recognizes that multiple Sustained Outages on an individual line can be caused by the same vegetation. As such, the Standard considers these multiple events caused by the same vegetation as a single Sustained Outage.

Sustained Outages— Falling Vegetation

R7. *Each Transmission Owner shall prevent Sustained Outages of applicable lines*[6] *due to vegetation falling into a conductor from within an Active Transmission Line Right of Way with the following exceptions:*

1. *Sustained Outages of applicable lines that result from natural disasters.*[4]
2. *Sustained Outages of applicable lines that result from human or animal activity.*[5]

Unlike grow-ins which are addressed in Requirement R5, a review of NERC disturbance reports related to blackouts indicates major blackouts were rarely if ever attributed to vegetation-related Sustained Outages due to vegetation falling into transmission lines. These events are known as fall-ins.

Sustained Outages due to fall-ins resulting from natural disasters are beyond the control of the Transmission Owner. In addition, it is often not possible in the aftermath of a natural disaster to perform the forensics necessary to determine what happened. Therefore, such Sustained Outages are not considered violations of this requirement.

Sustained Outages due to fall-ins that occur due to human or animal activity are beyond the control of the Transmission Owner. Therefore, such Sustained Outages are not considered violations of this requirement.

The Standard recognizes that multiple Sustained Outages on an individual line can be caused by the same vegetation. As such, the Standard recognizes these events as a single Sustained Outage.

Implement Annual Work Plan

R8. *Each Transmission Owner shall implement its annual work plan for vegetation management to accomplish the purpose of this standard within the extent of its easement and/or legal rights.*

This standard requires that the Transmission Owner implement the annual work plan and document this implementation. The annual work plan should allow sufficient time for reasonable procedural requirements to permit work on federal, state, provincial, public, tribal lands, such as permits for National Forest, Department of Transportation work, etc.

This Standard requires that the annual work plan be flexible to allow the Transmission Owner to change priorities during the year as conditions or situations dictate. For example, weather conditions (drought) could make herbicide application ineffective during the plan year. Another situational variance could be a major storm that redirects local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the Transmission Owner's system to work on another system. Examples of documented adjustments may include deferrals or additions to the annual work plan.

A measure for how this requirement was met may include documentation or other evidence of the work performed. Documentation may consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, QA work form, paid invoices, etc. to verify that the work has been completed. In addition, documentation of planned work that was deferred or not completed is needed. Documentation of deferred or incomplete work may include the reasons that the planned work was not completed. Where specific work on a line or lines was postponed, the expected completion date of the work may be included, if known. Other evidence may include photographs, inspection reports, walk-throughs, etc.

Designating Sub-200kV Lines

_R9._ *Each Reliability Coordinator in consultation with its Transmission Owner(s) and neighboring Reliability Coordinator(s) shall jointly prepare and keep current, a list of designated applicable lines that are operated below 200kV, if any, which are subject to this standard.*

Requirement R9 assigns to the Reliability Coordinator the task of designating sub-200kV lines that are subject to this standard. It can be seen that this Standard has departed from use of the term “critical” and replaced it with criteria that are more descriptive of the large disturbances this Standard intends to prevent.

The Standard places the responsibility on the Reliability Coordinator for the identification of specific sub-200kV circuits to which the Standard is to be applied. Identification of such sub-200kV circuits is to be done in consultation with the Reliability Coordinator’s Transmission Owners and neighboring Reliability Coordinators.

Reliability Coordinators can offer documentation that they have consulted with their Transmission Owners and neighboring Reliability Coordinators and that they have kept current a list of designated sub-200kV transmission lines that are subject to the Standard. Documentation may include letters, e-mails, spreadsheets, etc.

Documenting Method of Identifying Sub-200kV Lines

R10. *Each Reliability Coordinator shall document its method for assessing the reliability significance of sub-200kV lines considering all of the following:*

R10.1 *Transmission lines whose loss would result in the exceedance of an Interconnection Reliability Operating Limit (IROL)*

R10.2 *Transmission lines whose loss would place the grid at an unacceptable risk of instability, separation, or cascading failures.*

Requirement R10 assigns to the Reliability Coordinator the task of documenting its methods for assessing the reliability significance of sub-200kV lines.

List of Acronyms and Abbreviations

ANSI	American National Standards Institute
IEEE	Institute of Electrical and Electronics Engineers
IVM	Integrated Vegetation Management
NERC	North American Electric Reliability Corporation

References

[1] Andrew Hileman, *Insulation Coordination for Power System*, Marcel Dekker, New York, NY 1999

[2] EPRI, *EPRI Transmission Line Reference Book 345 kV and Above*, Electric Power Research Council, Palo Alto, Ca. 1975.

[3] IEEE Std. 516-2003 *IEEE Guide for Maintenance Methods on Energized Power Lines*

[4] G. Gallet, G. Leroy, R. Lacey, I. Kromer, *General Expression for Positive Switching Impulse Strength Valid Up to Extra Long Air Gaps, IEEE Transactions on Power Apparatus and Systems*, Vol. pAS-94, No. 6, Nov./Dec. 1975.

[5] IEEE Std. 1313.2-1999 (R2005) *IEEE Guide for the Application of Insulation Coordination.*

[6] 2007 National Electric Safety Code

[7] EPRI, *HVDC Transmission Line Reference Book*, EPRI TR-102764 , Project 2472-03, Final Report, September 1993

[8] ANSI. 2001. *American National Standard for Tree Care Operations – Tree, Shrub, and Other Plant Maintenance – Standard Practices (Pruning)*. Part 1. American National Standards Institute, NY

[9] ANSI. 2006. *American National Standard for Tree Care Operations – Tree, Shrub, and Other Plant Maintenance – Standard Practices (Integrated Vegetation Management a. Electric Utility Rights-of-way)*. Part 7. American National Standards Institute, NY.

[10] Cieslewicz, S. and R. Novembri. 2004. *Utility Vegetation Management Final Report.* Federal Energy Regulatory Commission. Commissioned to support the Federal Investigation of the August 14, 2003 Northeast Blackout. Federal Energy Regulatory Commission, Washington, DC. pg. 39.

[11] Kempter, G.P. 2004. *Best Management Practices: Utility Pruning of Trees*. International Society of Arboriculture, Champaign, IL

[12] Miller, R.H. 2007. *Best Management Practices: Integrated Vegetation Management.* Society of Arboriculture, Champaign, IL.

[13] Yahner, R.H. and R.J. Hutnik. 2004. *Integrated Vegetation Management on an electric transmission right-of-way in Pennsylvania, U.S.* Journal of Arboriculture. 30:295-300

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Comment Period Open
October 27–November 25, 2008

Now available at:
http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-07.html

First Draft of FAC-003-2 and Reference Document (Project 2007-07)

The Vegetation Management Standard Drafting Team (Project 2007-07) has posted its first draft of standard FAC-003-2 — Transmission Vegetation Management Program and an associated technical reference document for a 30-day comment period. The comment period is now **open until 8 p.m. on November 25, 2008**.

The drafting team revised the vegetation management standard in accordance with the Standard Authorization Request, which reflects comments from the FERC Order 693 and from stakeholders as well as procedural updates. The compliance elements, which are also part of the Standard Authorization Request, are not included in this initial posting. The drafting team has prepared and posted a technical reference document to supplement the FAC-003-2 standard along with a document comparing FAC-003-1 to FAC-003-2.

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Barbara Bogenrief at 609-452-8060.

The status, purpose, and supporting documents for this project — including an off-line, unofficial copy of the questions listed in the comment form — are posted at the following site:

http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Shaun Streeter,
Standards Program Administrator, at shaun.streeter@nerc.net or at 609.452.8060.

Individual or group. (66 Responses)
Name (43 Responses)
Organization (43 Responses)
Group Name (23 Responses)
Lead Contact (23 Responses)
Contact Organization (23 Responses)
Question 1 (62 Responses)
Question 1 Comments (66 Responses)
Question 2 (60 Responses)
Question 2 Comments (66 Responses)
Question 3 (61 Responses)
Question 3 Comments: (66 Responses)
Question 4 (59 Responses)
Question 4 Comments (66 Responses)
Question 5 (61 Responses)
Question 5 Comments (66 Responses)
Question 6 (58 Responses)
Question 6 Comments: (66 Responses)
Question 7 (59 Responses)
Question 7 Comments (66 Responses)
Question 8 (59 Responses)
Question 8 Comments (66 Responses)
Question 9 (59 Responses)
Question 9 Comments (66 Responses)
Question 10 (60 Responses)
Question 10 Comments (66 Responses)
Question 11 (58 Responses)
Question 11 Comments (66 Responses)
Question 12 (59 Responses)
Question 12 Comments (66 Responses)
Question 13 (56 Responses)
Question 13 Comments (66 Responses)
Question 14 (59 Responses)
Question 14 Comments (66 Responses)
Question 15 (60 Responses)
Question 15 Comments (66 Responses)
Question 16 (60 Responses)
Question 16 Comments (66 Responses)
Question 17 (58 Responses)
Question 17 Comments (66 Responses)
Question 18 Comments (66 Responses)

Individual
JAMES W. SMITH
ITC HOLDINGS
Disagree
ITC does not agree with the new purpose statement. The NERC Glossary of terms states that the BES â€¦.generally operated at voltages of 100kV or higher and the Applicability in Section 4 clearly states the standard is intended to apply to all line voltages of 200kV and above and those lines designated by the Reliability Coordinator (4.2.1) as being subjected to this standard. Using the term Bulk Electric System (BES) clearly sends a confusing message and should be eliminated. Thus the term of "electric transmission system" is appropriate for the standard
Agree
ITC agrees that the Reliability Coordinator is the appropriate entity to identify and designate any sub - 200kV lines deemed applicable to the standard with the concurrence of the Transmission Owner.

Agree
The standard doesn't actually explain or define the Active Transmission Line Right of Way.
Agree
Agree
Agree
Disagree
Agree & Disagree with the question: Agree with the need to have an Imminent Threat Procedure and upon discovery of an IT, the Transmission Operations (TO) should be notified. We Disagree however, with the requirement as written as its too prescriptive and is open to interpretation, from an audit perspective, with use of the term â€œimmediateâ€□ communication and a partial list of activities that the TO may consider. Decisions on what specific system operating actions that could be taken are beyond the responsibility of the vegetation management personnel. Disagree with the need to implement the imminent threat procedure merely because a CCZ is being approached. It is possible that the CCZ is being approached by vegetation at the lowest point of the CCZ where the conductor may be at its highest point in the CCZ, (potentially 20 or 30 feet from vegetation) and wouldnâ€™t necessitate notification to the TO. Is there a desired distance from the CCZ where this procedure must be implemented since all vegetation within a Right-of-Way will approach the CCZ as it grows? R1.4 should be changed to â€œRequire a process for response to vegetation related imminent threat to applicable lines and not the CCZ
Agree
Agree
Agree
Disagree
Just because vegetation is approaching the CCZ doesn't represent an imminent threat and should not be set to an imminent threat procedure. Implementation of R2 would require field personnel to determine the speculative position of the line during inspections to decide whether to engage the imminent threat procedures. While we agree that an imminent threat procedure should be implemented to address vegetation related imminent threats as soon as they are identified, we believe that an approach of the CCZ should not be used to generate implementation. The term "approached" does not identify a specific distance, so itâ€™s not clear to what extend vegetation would have to approach the CCZ to require implementation of the imminent threat process. ITC agrees that the implementation of an imminent threat procedure may be a valid concept, but visualization of the CCZ and determining approaching vegetation is a practice in hypothetical conductor locations in real time. This may be a good imaginary concept in understanding conductor movement but it's impractical for field applications.
Agree
Agree
Agree
Disagree
First, itâ€™s impossible to determine that no encroachments into the CCZ have occurred at any time and determination of the CCZ from the field perspective is problematic. The standard is ambiguous and it seems like clear cutting is the underlining message that is wanted. Determining an encroachment into the CCZ is problematic due to the need for survey accuracy measurements and engineering evaluations. This will also lead to questions about the ability to audit this requirement.

The CCZ changes in size and shapes continuously in each and every span and will be difficult to monitor. This would require field personnel to spend numerous hours estimating and attempting to measure potential encroachments of the CCZ. The way R4 is currently written the Transmission Owners would be required to self-certify compliance with R4, and which we donâ€™t think this is possible. This will lead to audit issues with more scrutinizing and potentially more penalties or fines. It is important to recognize that the ultimate goal of the standard is to ensure that vegetation management is conducted in order to maintain an adequate level of reliability, and not to precisely measure clearance zones. Alternative 2 would be the most logical choice, depending on easement/legal rights, with changes that would eliminate any reference to a trigger point into the encroachment zone of the CCZ to; measuring encroachment to a fix distance (Gallet tables) observed by field personnel
Agree
Agree
Clarifying the intent for the annual plan is to focus on the Active Rights of Way will prevent interpretation conflicts
V1 was a better written standard and had clear requirements on reporting and who was to report violations etc. When and how are violation to be reported is not mentioned in the V2. The standard should clearly identify all reporting requirements. Standard development should focus on practicality for the field personnel in terms of implementing the standard and enforceability. Version 2 is not as user friendly for field personnel and ambiguous at best which requires an impractical and unrealistic level of performance from the industry. This standard needs to stress that it applies to vegetation within the Active Transmission Right of Way. Vegetation from outside the active ROW, falling through the CCZ should not be a violation. V2 needs further clarification of the definition of the active ROW.
Individual
Richard Dearman
Tennessee Valley Authority
Disagree
TVA feels the use of the term Bulk Electric System will cause unnessesary confusion to the industry concerning applicability of this standard. TVA recommends the continued use of the undefined term "electric transmission systems. TVA recommends changing the phrase "by preventing vegetation-related outages that could lead to Cascading" to "by preventing those vegetation-related outages that could lead to Cascading", this removes the improper inference that each vegetation-related outage leads to Cascading
Agree
TVA agrees with Comment question 2
Agree
TVA agrees with Comment Question 3
Agree
TVA agrees with Comment Question 4
Disagree
TVA suggests that R1.2 be changed by adding "except in cases where lines or significant sections of lines are over terrain which is void of vegetation(such as bodies of deep water)or over terrain void of any vegetation that can grow to a mature height that could threaten the conductors, then longer cycles will be acceptable". This would avoid unecessary expenses in such cases.
Agree
TVA agrees with Comment Question 6 and proposes that the Annual Plan be a defined term.
Disagree
TVA recommends that R1.4 and R2 both be removed from this Standard. This is a "zero tolerance" Standard with significant penalties for outage violations. These penalty conditions are the necessary and sufficient conditions for the Transmission Owner to immediately react to any discovered threats to prevent potential outages.
Agree

TVA agrees with Comment Question 8
Agree
TVA agrees with Comment Question 9
Agree
TVA agrees with Comment Question 10
Disagree
TVA recommends that R2 be removed from this standard. Since this is a "zero tolerance" standard there is a very significant incentive for the Transmission Owner to inspect and plan maintenance to prevent potential outages. The Gallet Equations should be kept within the white paper solely for the TO to reference for developing maintenance and inspection cycles.
Disagree
TVA agrees with this concept however as stated in Comment Question 11 response, this should be an element of the White Paper and should not be in the Standard Requirement.
Disagree
TVA agrees with this concept however as stated in Comment Question 11 response, this should be an element of the White Paper and should not be in the Standard Requirement.
Agree
TVA agrees with Comment Question 14
Disagree
TVA recommends that R4 be removed from this standard. Since this is a "zero tolerance" standard with substantial penalties for controllable vegetation related outages there is an overwhelming incentive for the Transmission Owner to proactively perform inspections, preventative maintenance, inpections and corrective maintenance to prevent potential outages. As such, R4 does not add any value to improving reliablity while causing numerous unresolvable problems.
Agree
TVA agrees with Comment Question 16.
Agree
TVA agrees with Comment Question 17
Group
Associated Electric Cooperative Inc.
John Neagle
Associated Electric Cooperative Inc.
Disagree
The definition of Bulk Electric System includes most transmission lines operated at 100 kv and above. While Section A.4.2.1 limits the applicability of FAC-003-2 to 200 kv and higher transmission lines, the use of the term Bulk Electric System could cause unnessary confusion. Associated Electric Cooperative Inc recommends the continued use of the term "electric transmission systems."
Disagree
Associated Electric Cooperative Inc does not believe the Reliability Coordinator (RC) is the appropriate entity to determine whether or not selected sub-200 kv transmission lines should be subject to this standard. The planning horizon for the RC is typically much shorter than the time needed to incorporate a sub-200 kv transmission line into a vegetation management program. Associated recommends Planning Coordinator be designated as the applicable functional entity and be substituted wherever Reliability Coordinator appears in the Standard.
Disagree
Associated Electric Cooperative Inc agrees with the changes described in Question 3 except for the definition of Active Transmission Line Right of Way. Associated suggests the term be revised to "Active Right-of-Way" for consistency with the present Glossary term "Right-of-Way" and that the definition of Active Right-of-Way be revised to explicitly permit the Transmission Owner to solely determine the appropriate width. A suggested definition is "Active Right-of-Way: The portion of Right-of-Way utilized for active transmission facilities. The width of the Active Right-of-Way, as determined

by the Transmission Owner, shall be consistent with the Transmission Ownerâ€™s normal standards and practices and shall be consistent with good utility practice for other transmission lines of similar voltage and configuration. Inactive or unused portions of the Right-of-Way, intended for future transmission lines or other facilities, may be excluded from the Active Right-of-Way."
Agree
Disagree
While Associated Electric Cooperative Inc agrees with this requirement in general, there may be areas (e.g. highly arid terrain, open water, etc.) where an annual interval is unnecessary and adds little or nothing to reliability.
Agree
Disagree
The language in R1.4, requiring notification of the Transmission Operator, is inconsistent with the Applicability in Section A.4.1.1 which designates the Transmission Owner as the responsible entity.
Agree
Agree
Agree
Disagree
The phrase â€œâ€¦Critical Clearance Zone is approachedâ€¦â€☐ in R2 is nebulous and probably unenforceable. The determination and visualization of the Critical Clearance Zone and approaching vegetation encroachment, under field conditions, is a practice in application of theoretical conductor locations in real time. Would the Transmission Owner be found in noncompliance if evidence showed vegetation had â€œapproachedâ€☐ within 20 feet, 2 feet, 2 inches or some other arbitrary distance of the CCZ and the TO failed to implement its imminent threat procedure?
Agree
Agree
Agree
Disagree
Associated Electric Cooperative Inc believes this requirement, as written, is unreasonable since it would prevent (or at least result in noncompliance) the intrusion within the Critical Clearance Zone (CCZ) of anything or anyone, including qualified line workers and their tools. It is suggested the words â€œof vegetationâ€☐ be added between encroachment and within. The requirement would then read, â€œEach Transmission Owner shall prevent encroachment of vegetation within the Critical Clearance Zone of its applicable lines with the following exceptions:â€☐ The complexity of determining an encroachment into the Critical Clearance Zone is overly burdensome, requiring engineering calculations and possibly the need for precision measurements. The Transmission Owner (TO) cannot demonstrate compliance with the Requirement and its companion Measure, M4, since a negative cannot be proven. Therefore, since the TO must demonstrate compliance (guilty until proven innocent), it is automatically in violation of the Standard.
Disagree
Requirements 5, 6 and 7, as written, compel the Transmission Owner to allocate precious resources to ensuring a vegetation related outage will NEVER occur on any applicable transmission line, regardless of the line's true importance to maintaining electric transmission system reliability. All lines are not created equal; only those which are an IROL or contribute to IROLs should be held to a zero tolerance standard.

Agree
R9 and R10: Associated Electric Cooperative Inc does not believe the Reliability Coordinator (RC) is the appropriate entity to determine whether or not selected sub-200 kv transmission lines should be subject to this standard. The planning horizon for the RC is typically much shorter than the time needed to incorporate a sub-200 kv transmission line into a vegetation management program. Associated recommends Planning Coordinator be designated as the applicable functional entity and be substituted wherever Reliability Coordinator appears in the Standard. M1.4: The language in M1.4, requiring immediate communication of an imminent threat to the Transmission Operator, is inconsistent with the Applicability in Section A.4.1.1 which designates the Transmission Owner as the responsible entity. M4: The preparation and retention of inspection reports, imminent threat reports, quality assurance reports, etc. is appropriate. These reports would not, however, absolutely demonstrate the Transmission Owner had experienced no vegetation encroachments into the Critical Clearance Zone. A negative cannot be proven. M6 and M7: The Transmission Owner is again expected to demonstrate a negative to prove compliance. Section C: Associated Electric Cooperative Inc recognizes the Standard, as posted, is a first draft for comments and will likely be revised before submittal for ballot. However, the Compliance section should be posted for an adequate comment period prior to balloting.
Group
NPCC
Guy Zito
NPCC
Agree
Disagree
While we agree with the suggested changes, we believe that the TVMP should be focused on removal of incompatible vegetation from the Active Right of Way. We recommend using the following phrase in R1: "designed to remove incompatible vegetation on its Active Transmission Lines' Rights 0f Way" instead of "designed to control vegetation on its Active Transmission Lines' Rights of Way". Incompatible vegetation should be defined as any vegetation which has the potential to grow tall enough to jeopardize the integrity of an applicable transmission line by growing into the CCZ or falling into the CCZ. This would provide clear guidance to all stakeholders, support long term vegetation management philosophies, and complement methods such as IVM where incompatible vegetation is completely removed, and compatible vegetation is encouraged to proliferate, thereby helping to control incompatible vegetation in an environmentally positive manner. Removal of incompatible vegetation is superior to pruning, topping, and trimming in terms of short and long term reliability of the Bulk Electric System. This language would also serve to align NERC and FERC with Transmission Owners who attempt achieve the highest degree of reliability by exercising their full easement rights in cases where strong opposition from landowners and public officials is encountered. If such language is adopted it should apply to R1 and the TVMP. It should be made clear in the technical reference document that removal, rather than pruning of incompatible vegetation is the philosophy that must be incorporated into the TVMP. It must be clearly explained that Transmission Owners have the flexibility to perform removals gradually over several treatment cycles in sensitive areas as long as pruning is performed as an interim measure to ensure that CCZ encroachments and on-Right of Way fall overs do not occur. It must also be made clear that the presence of incompatible vegetation on the Right of Way will always occur and does not in itself constitute a violation of the Standard.
Agree
Disagree
There were differing opinions within the group. Those entities with extensive overhead transmission felt the once a year requirement was overly prescriptive and would not improve reliability, others were in agreement with the "at least once per calendar year" requirement.
Disagree

R1.2 and R1.3 should specifically state calendar year, and the Annual Plan and inspection follow the same calendar year timing.
Disagree
While we strongly agree that an imminent threat procedure should be required in the TVMP, we disagree with some specific wording in R1.4. R1.4 requires immediate communication of an imminent threat to the Transmission Operator, which we would normally agree with. R2 however requires that the imminent threat procedure be implemented when the Critical Clearance Zone (CCZ) is approached by vegetation. "Approached" is not defined as a specific distance, so this part of the requirement is left up to the individual's interpretation. In cases where the CCZ is approached by vegetation no threat to the system is possible if the vegetation is removed before it actually grows into the CCZ. In many cases the vegetation can be removed without taking clearance outages because the CCZ is large, and the conductor and vegetation are still relatively far apart. In such cases there is no need to notify the Transmission Operator, although there is a need to remove the vegetation immediately. We recognize that the opposite is also true, and that in some cases it will be necessary to notify the Transmission Operator because a clearance outage or line de-rating may be required to remove the vegetation. We therefore suggest a simple change to the wording of the second sentence of R1.4. Change "â€¦. specify actions which shall include immediate communication of the threat to the Transmission Operator, and may include actions such as a temporary reduction in line Rating, switching lines out of service, or other actions" to "... specify actions which may include immediate communication of the threat to the Transmission Operator, a temporary reduction in line Rating, switching lines out of service, or other actions". This change will address the issue which is described above and will allow each Transmission Operator to develop an imminent threat procedure that best fits their system. It should also be noted that many Transmission Operators have imminent threat procedures in place to address all imminent threats to their transmission system, not just threats due to vegetation. It makes sense for Transmission Owners to have only one imminent threat process, therefore the flexibility that can be achieved in the context of this standard would be helpful.
Agree
Agree
We agree but believe that the TVMP should target removal of all incompatible vegetation on the Active Right of Way as described in the response to question 3.
Agree
Agree
Agree
Agree
Agree
Disagree
The purpose of the standard is "To improve the reliability of the Bulk Electric System by preventing vegetation related outages that could lead to Cascading". We believe that R4 is not the most effective way to achieve this purpose because it does not provide incentive for Transmission Owners to take advantage of modern technology, such as aerial laser survey (ALS) using Light Detection and Ranging technology (LIDAR), that is capable of accurately identifying vegetation which is approaching the CCZ or has encroached into it. In fact R4 provides an incentive not to utilize this technology because Transmission Owners who identify encroachments would be in violation of R4 for each identified encroachment. On the other hand, Transmission Owners who choose to be less proactive often would not identify such encroachments because the CCZ and encroachments of it are generally not easy to determine without taking precise measurements. Unless the line is heavily loaded or the vegetation is significantly overgrown, encroachments of the CCZ would not be readily noticed. In most cases these Transmission Owners would simply remove or cut back incompatible vegetation without taking

measurements. The threat to the line would have been eliminated with no encroachment having been identified. R4 presents a dilemma for Transmission Owners that are considering making the significant investment in ALS technology. While the technology would allow them to identify any potential grow-in or fall-in conditions, it would also expose them to the risk of identifying violations of R4, that would otherwise not have been identified. Violation Risk Factors (VRFs), Violation Severity Levels (VSLs), and Time Horizons are not included in this Draft, but after making a significant investment in ALS, Transmission Owners could be faced with significant additional cost in terms of NERC penalties. In addition, even if the penalties were relatively low they would be exposing themselves to violations that less proactive Transmission Owners would not be exposed to. In our view R4 as written would, in some cases, have the opposite effect of what is intended because the business case for using ALS is more difficult to make. This will result in less use of ALS and other emerging technology that is likely to be developed. This would result in fewer problems being identified, a small percentage of which will not be discovered until they result in a line trip. Still we believe that the concept of the CCZ is a good one and recommend that R4 be changed so that Transmission Owners are provided with an incentive to invest in the best technology available in order to ensure the highest level of reliability. The opportunity exists to develop the standard in a manner that encourages the industry to take advantage of new technology and manage vegetation in a very proactive way. We recommend that R4 be changed as follows: Modify R4 to require Transmission Owners to immediately implement the imminent threat process defined in R1.4 when they identify instances where the CCZ is approached or encroached upon. Failure to do so would be a violation of R4. Eliminate encroachment of the CCZ as a violation of R4. This would eliminate R2 and incorporate implementation of the imminent threat process into R4. Require Transmission Owners to report to the Regional Entity on a quartely basis any instances where the imminent threat process was implemented due to an encroachment of the CCZ. This would add a reporting requirement for Transmission Operators. Require Transmission Owners to report to the Regional Entity on a quarterly basis any instances where either a momentary or sustained outage was caused by grow-ins, Active Transmission Line Right of Way blow-ins, or Active Transmission Line Right-of-Way fall-ins. This would add three additional reporting requirements for Transmission Operators. Require Regional Entities to perform additional audits of Transmission Owners that exceed metrics for violations of the CCZ . The metrics would be established in this Standard based upon 100 circuit miles of applicable lines. This would add an additional requirement for Regional Entites. This concept would result in a more rigorous standard than FAC-003-01 because of the additional reporting and auditing requirements. It would drive proactive behavior throughout the industry and provide a significant incentive for Transmisison Owners to invest in new technology such as ALS that is capable of accurately identifying vegetation that has approached or encroached upon the CCZ. We believe that this change would result in the identification of more incipient vegetation-related problems and fewer vegetation-related outages as soon as it was implemented and would best support the purpose of the Standard.
Disagree
NPCC participating members request clarification if violations of R5, R6, and R7 result in outages that must be reported.
Agree
NPCC requests that the Standard Drafting Team review the compliance and reporting requirements for consistency and adequacy.
Individual
Chris Scanlon
Exelon
Agree
Agree
Agree
Agree
Refer to footnotes in R1.1 and 1.2. Are applicable entities to be held accountable to ANSI A300

(footnote 2) and for providing documentation to support analysis that "local factors" were accounted for (footnote 3)? These footnotes should be requirements or they should be removed and included in a Reference Document not subject to compliance audit.
Agree
Agree
Agree
Agree
Disagree
We do not understand the reference to "fill in the blank" requirement for Clearance 1. As commonly understood, a "fill in the blank" standard /requirement is one that was assigned to the RRO. Clearance 1 in FAC-003-1 is a TO requirement. The reference to a clearing zone should be retained, as each TO will need to define this in their program so as to avoid encroachments into the CCZ.
Agree
Agree but same comment as above,we do not understand the reference to "fill in the blank" requirement for R1.3. As commonly understood, a "fill in the blank" standard /requirement is one that was assigned to the RRO.
Disagree
Comments: 1) In spite of the rigor associated with the Gallet equations, the definition of CCZ is imprecise as the Ratings to be used are not specified. In addition, Exelon is concerned that it will be difficult to determine the CCZ for each span under all possible operating conditions. Implementing an imminent threat procedure (R2) in combination with the CCZ may be unworkable under actual field conditions. 2) We are concerned that CCZ is only fully defined in the Technical Reference documentation and not in the standard itself. As stated in the NERC Standards Process Manual, Elements of a Reliability Standard, "Supporting documents to aid in the implementation of a standard may be referenced by the standard but are not part of the standard itself." There needs to be enough specificity as to the definition of CCZ in FAC-003-2 so that adequate documentation and evidence of compliance can be developed.
Disagree
Comments: By using the Gallet equations, the draft standard appears to support reducing the clearance requirements as compared to IEEE 516. Given what we believe would be the difficulties in applying the clearances as developed using the Gallet equation method, we question if dropping the IEEE 516 guidance could have the unintended consequence of reducing reliability.
Disagree
We disagree with the T factors that are proposed as our design is more conservative.
Agree
Disagree
The first bullet is unworkable in the real world. It will be virtually impossible to prove that "no encroachments of the CCZ have occurred anywhere at any time during the compliance period". The effort to do this will not enhance reliability. In fact, in may harm reliability by requiring unnecessary investments and O&M expenditures that could be better spent on real reliability enhancements. Exelon agrees, subject to the development of a workable definition of the CCZ, that the second bullet is the preferred approach.
Disagree
It appears to Exelon that the requirements of the standard have been written and modified at different times and as a result the document lacks a degree of consistency and coherence. While the Standard mentions encroachment of the CCZ and Sustained Outages as potential violations, it is completely silent on how momentary outages should be addressed. Exelon views the following events as a risk continuum that should be addressed in the Standard and handled as a part of the VRFs and

VSLs - encroachment of the air gap distance, momentary outages and Sustained Outages.
Disagree
Strike "within the extent of it's easement and / or legal rights." This is unnecessary and will cause confusion. The annual work plan as required to be developed per R1.3 requires consideration of permitting, scheduling and regulatory limitations.
Applicability. 4.2.2 is unclear. If 4.2.2 is intended to cover Generator Owner interconnections, say so uniquivocally. Do not rely on future changes to the NERC Registry Criteria or other "global" solutions if the intent is to make the standard applicable to Generation Owners who own generator leads. Exelon would like to reemphasize our concern with implementing the requirements if the Gallet equation derived CCZ is used. ANSI A300 part 1 and part 7 should be part of the standard as they provide independently recognized valid methods and guidance to conduct maintenance on the ROW corridor.
Individual
Weston Davis
Central Maine Power Company
Disagree
Central Maine Power suggests that a definition be provided for Bulk Power.
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Disagree
Central Maine Power Company disagrees with removal of clearance 1. The clearance 1 was included so that professional arborists could establish the clearanace necessary for a transmission owner to reduce the risk of a tree caused power outage. The transmission owner should use ANSI- Standard A300, including PART 7, and other publications to develop best management practices which include clearances at time of maintenance. Clearance 1 provides leverage for Transmission Owners to achieve the clearances stated in their TVMP.
Disagree
Central Maine Power Company disagrees with the removal of the qualification statement. The individual responsible for this critical program must be qualified through experience, training, and education. The International Society of Arboriculture has a certification program that can help with guidelines for qualified arborists.
No comment
Agree
Agree
Agree
Disagree
Central Maine Power Company suggests the second alternative to R4 as recommended above, which

is to require immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the critical clearance zone, thus preventing an outage. This alternative is similar to R2, therfore R4 may not be required.
Agree
Central Maine Power Company suggests that R8 read as A Transmission Owner shall implement its annual work plan within the Active Right of Way to the the extent of its easements or legal rights.
The White paper is an important support document and should remain as an attached reference to FAC 003. The white paper should clarify that capable tree species should always be removed from the border zone, except in selected areas where topography includes deep ravines.
Individual
Thad Ness
American Electric Power (AEP)
Disagree
American Electric Power ("AEP") does not agree with this purpose statement. First, it is clear from the Applicability (in Section 4) that the standard applies only to certain lines, not to the entire Bulk Electric System (BES). Reference to the BES in the Purpose statement tends to muddy the water, potentially leading to an assumption that the Standard indeed applies to the entire BES. AEP suggests that the term BES used herein be replaced with "electric transmission system" or "transmission grid". Second, the phrase "by preventing vegetation-related outages that could lead to Cascading" should be changed to "by preventing those vegetation-related outages that could lead to Cascading", to remove any suggestion that all vegetation-related outages could lead to Cascading.
Agree
AEP concurs with the drafting team that the Reliability Coordinator is the appropriate entity for identifying sub-200kV lines (if any) that would be subject to the Standard.
Agree
While Requirement R1 does not actually define "Active Transmission Line Right of Way" (it is defined on page 2 of the Standard), AEP concurs with R1, except as noted below for R1.4.
Agree
AEP agrees with these changes from Version 1.
Agree
AEP agrees with this change.
Agree
AEP agrees with these changes.
Disagree
AEP agrees with the need for a TO to have an Imminent Threat Procedure and that the Transmission Operator should be immediately notified of imminent threats. However, AEP disagrees with the requirement that the Transmission Operator be notified merely because the Cricitical Clearance Zone (CCZ) has been approached. It is possible that the CCZ is encroached by vegetation at the lowest point of the CCZ whereas the conductor may be at its highest point in the CCZ (potentially 20 or 30 feet away from the vegetation). This situation does not merit notification to the Transmission Operator. Please also refer to our comments regarding CCZ in AEP's responses to Questions 15 and 18.
Agree
Agree
AEP agrees with the removal of Clearance 1 from the Standard.
Agree
AEP agrees that the Standard should not stipulate or require personnel qualifications.
Disagree
AEP agrees with the need for a TO to have an Imminent Threat Procedure and that the Transmission Operator should be immediately notified of imminent threats. However, AEP disagrees with the

requirement that the Transmission Operator be notified merely because the CCZ has been approached. Vegetation approaching the CCZ does not necessarily constitute an imminent threat. It is possible that the CCZ is encroached by vegetation at the lowest point of the CCZ whereas the conductor may be at its highest point in the CCZ (potentially 20 or 30 feet away from the vegetation). This situation does not merit notification to the Transmission Operator. Please also refer to our comments regarding CCZ in AEP's responses to Questions 15 and 18.
Agree
AEP agrees that the Gallet Equation method is a reasonable and appropriate replacement for the IEEE 516 method.
Agree
AEP agrees that the choice of transient overvoltage factors is sufficiently sound.
Agree
AEP agrees with this change.
Disagree
AEP disagrees with the proposed requirement that violations be automatically declared if the CCZ is encroached. Instead, AEP would support a standard utilizing the first alternative proffered in these comment questions. While the CCZ is an interesting theoretical concept, it is not realistically feasible in the field to implement a concept that depends on accurate measurements and calculations. Further, the proposed requirement offends common notions of reliable maintenance methods, because it demands that forestry crews stop work if they see a potential encroachment and that surveyors and engineers be brought in to take detailed measurements and perform complex calculations to determine whether an encroachment has in fact occurred. The need for a reliable transmission grid would be much better served by a standard utilizing the first alternative, in which no violation occurs in the event of an encroachment as long as the TO implements its imminent threat procedure and removes the vegetation. While seemingly technically appealing, the CCZ concept is fraught with implementation difficulties. It should not be used as a Pass/Fail zero-tolerance decision point to determine whether a violation has occurred. After all, a zero-defect condition has not been achieved in many other aspects of electric utility operation. For instance, the utility industry attempts every year to conduct its business without any workplace deaths, yet deaths occur every year. Many millions of dollars are spent by North American utilities to promote safety programs and safe work procedures, but some work-related vehicle accidents and personal injuries still occur. Also, utilities aggressively investigate electric switching errors and have instituted rigorous dispatcher-training programs, but a few switching errors still occur. For an industry in which billions of stems of vegetation must be managed, even a high six-sigma level of quality would still result in a few cases annually of imperfectly managed vegetation. It is unreasonable to expect zero-tolerance perfection with the CCZ concept. Also, with the way R4 is worded, a tree falling from outside the right of way would result in a violation if it passed through the CCZ, whether it resulted in an outage or not. It is not appropriate to place a burden on the TO for such circumstances outside the TO's control. As R4 is written, it appears that there is no way that a TO could certify at the end of the year that it has maintained a CCZ free of encroachments, even if no outages occurred. AEP believes a more effective and reliability-centered approach would be one where TOs are expected to implement their imminent threat procedure if vegetation is encroaching upon the Gallet equation distance. If TOs act accordingly and remove the vegetation without incurring an outage, then they would not be in violation. However, if the TOs knew of vegetation encroaching upon the Gallet equation distance but failed to implement their imminent threat process, they would be in violation and be obliged to report the event.
Agree
AEP is in agreement with these changes.
Agree
AEP agrees with this change.
The definition for Critical Clearance Zone (CCZ) on page 2 of the proposed draft Standard does not specify the Rating (summer, winter, normal, emergency, etc.). This suggests that different CCZs apply at different times of the year and thus that vegetation in the area might be outside the CCZ at certain times of the year and inside the CCZ at other times. AEP suggests that this may not have been the intent of the drafting team. Also, the term "design blowout" is not defined; thus, it appears that it will be up to the TO and the auditor to determine the bounds of the CCZ. AEP again suggests

that this may not have been the intent of the drafting team. Requirement R8 contains the clause "within the extent of its easement and/or legal rights". This intent of this clause is unclear and its rationale is not obvious. AEP suggests that this clause be removed or at least reworded for clarity.
Individual
Deborah Schaneman
Platte River Power Authority
Agree
The use of the approved terminology, Bulk Electric System, from the NERC Glossary of Terms is better than the undefined term electric transmission systems.
Agree
The Reliability Coordinator is better able to identify lines under 200 kv that would exceed an Interconnection Reliability Operating Limit (IROL), cause instability, uncontrolled separation, or cascading outages resulting from a vegetation related outage than the Regional Entity.
Agree
The list of terms, "objectives, practices, approved procedures and work specifications," from version 1 provides more clarity thatn the one word "methodology" and should bot be replaced. The newly defined term "active transmission line ROW" provides clarity to the portion of the ROW requiring vegetation management and is a valuable addition to the standard.
Agree
The separation allows lower sanctions and penalties to be assessed for weak documentation and higher sanctions and penalties to be assessed for weak inspection programs and weak vegetation management. However, the standard would be easier to follow if the two elements were kept together in the document.
Agree
The inspection frequency is reasonable.
Agree
Under the new working in R1., the TVMP no longer has a requiremnt to include objectives. However, there is a phrase in R1.3. to "support the objectives... and methodologies outlined in the TVMP". R1.3. should be consistent with the wording in R1.
Agree
Imminent threat is not a defined term in the NERC Glossary of Terms so it could be construed as a fill-in-the-blank requirement by FERC as each Transmission Owner could define Imminent Threat differently. Imminent threat should be defined or the requirement should be reworded to define what types of situations would require a procedure. Also, the language, "and may include actions such as a temporary reduction in line rating, switching lines out of service, or other actions" should be removed from the standard but could be included in the imminent threat procedure or definition.
Agree
The term corrective action plan adds clarity.
Disagree
Clearance 1 could be defined in the standard in tables developed using IEEE Standards for various voltages, line spans and altitudes. Clearance 1 provides justification and leverage for operational clearances when dealing with organizations such as municipalities. Without Clearance 1, utilities could be mandated in specific situations to clear so that the vegetation is just beyond the CCZ at all times. This could result in pruning at six month intervals, which is not feasible or cost-effective.
Agree
The requirement should be removed because it is a "fill-in-the-blank" requirement. Defining the proper amount of personnel qualifications and training would be too prescriptive for utilites with small vegetation management programs and not prescriptive enough for utilities with large vegetation management programs.
Disagree
Changing to the Gallet equation will not have a large impact on vegetation management operations, keeping Clearance 1 and 2 with tables developed using IEEE Standards for various voltages, line spans and altitudes is preferable. Actions should be taken to prevent an outage when vegetation

encroaches Clearance 2.
Agree
Changing this will not have a large impact on vegetation management operations, so we have no concerns.
Agree
Changing this will not have a large impact on vegetation management operations, we have not concerns.
Agree
The separation allows lower sanctions and penalties to be assessd for a weak schedule and higher sanctions and penaltites to be assessed for not implementing schedules. However, we feel that the sandard itself would be easier to follow if it was re-organized so that the requirement to have the schedule is kept together with the requirement to implement it.
Disagree
This requirement should be removed completely. It is too stringent and it is impossible to prove compliance through documentation. Encroachemnt of Clearance 2 (or CCZ) should be addressed in the imminent threat procedure.
Disagree
The requirement under R7 should be changed from "shall prevent sustained outages" to "shall minimize sustained outages due to vegetation falling into a conductor." We note the word "minimize" was present in earlier drafts of the docuement. We are concerned about the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. This could lead to an incident where utilities are charged unreasonably - for example, for an outage from a tree that was one foot within the active ROW line. We should not be held liable when reasonable due diligence is practiced.
Agree
The separation allows lower sanctions and penalities to be assessed for a weak plan and higher santions and penalties to be assessed for not implementing an annual plan. However, we feel that the standard itself would be easier to follow if it was re-organized so that the requirement to have a plan is kept together with teh requirement to implement it.
The white paper ensures consistent interpretation of the standard. Perhaps the lack of such a paper in the first version of the standard contributed to the varying interpretations.
Group
WECC Reliability Coordination
Linda Perez
WECC RC
Agree
Agree
This would be a new function in WECC RC, we are not currently staffed to perform this function.
Agree
Agree
Agree
Agree
Agree
Agree

Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
R9 Should a dispute arise, how are thoes disputes resolved. Who keeps the list. R10 What is acceptable methodology given the lack of interpetation of of unacceptable risk of instability(R 10.2) or cascading failures. There is no definition of the consequences if a sub 200kv line is left off the list for vegitation management, and caused a cascading outage or placed the grid at an unacceptable risk of instability.
Individual
Alan Gale
City of Tallahassee
Agree
Agree
Agree
Agree
See Question 6 and 17.
Disagree
While TAL's specific conditions and current process would meet this requirement, I can envision where some conditions may not require an annual inspection. These might include desert conditions, crop fields, over water, etc. To dictate a specific one-year requirement could be burdensome to some utilities with no improvement to the relibility of the BES.
Disagree
While I can agree with a separate requirement (R8) to implement the plan developed in R1.3, they need to both have the flexibility desired in R1.3. I do not see that flexibility in R8. See response to question 17.
Agree
Disagree
The use of the term "interim corrective action" implies that a permanent solution or return to the original plan must be pursued. I would change this to "alternate maintenance" process to prevent non-compliance if the TO is constrained and has reached an agreement with the land owner that

works to maintain the reliability of the line.
Agree
Agree
Agree
As long as we do not have to have evidence of using the calculation! We should be able to use Table I as provided.
Agree
Agree
As long as we do not have to have evidence of using the calculation! We should be able to use Table I as provided.
Agree
Disagree
VEHEMENTLY DISAGREE! The purpose of the standard is to prevent vegetation related outages. A violation should occur if an outage occurs. As written, R4 and M4 would be impossible to prove or disprove. It is not like we can get up there with a tape measure and measure it. R2 requires action if the CCZ is "approached". This is undefined and subject to a myriad of interpretations. Evidence is hard enough to obtain to the satisfaction of the Compliance Monitor. To require sufficient evidence to prove that something didn't occur is a tremendous burden and is not a wise expenditure of vegetation management dollars. Let us spend the money on trimming and not on paperwork. As an alternative replace "encroachment within the Critical Clearance Zone" with "vegetation caused outages". This would allow the same exceptions and is much easier to prove or disprove with a breaker operation. Although this would result in the cause of every breaker operation being tracked, it is a tangible evidence requirement and leaves very little room for interpretation. The levels of fines have already shown that vegetation management is a serious standard and we had better comply.
Agree
Why have we gone backwards with only "Sustained Outages" being a violation? Even a momentary outage indicates that a violation has occured if the cause was vegetation related (with the same exceptions). This would seem to contradict the proposed R4. If it wasn't a Sustained Outage it wasn't a violation? If you have a sustained outage due to vegetation, you must have violated the CCZ.
Disagree
Combined with Question 6. R8 needs to have the same flexibility that R1.3 has. As written, it could be argued that you have to do everything in your annual plan, AND anything in addition due to the changing conditions. This contradicts what is put forth in the white paper. I would add "as modified per R1.3" after "implement it's annual work plan for vegetation management"
Attachment I. Titles are different between page 8 and 9. Page 8 should have (D) after Distances. Page 9 should have indication that it is "continued" since the table spans multiple pages.
Individual
Fred Young
Northern California Power Agency (NCPA)
Agree
Agree
Agree
Agree
Agree

Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Section A. 5. Effective Dates: This is extremely vague and I would not know the actual effective date. Whose regulatory approval is needed? If this is meant to leave flexibility between FERC and the Canadian entities, please write it that way. Most effective dates are clear and concise, i.e., "the first month following apporval by FERC". Let's clear this up and avoid a subsequent interpretation request.
Individual
Jason Lietz
Northern Indiana Public Service Company
Agree
Agree
Disagree
Use of the term "have" is a notable and unnecesssary weakening versus the terms "prepare and keep current". One of the key lessons learned from past vegetation related outages and subsequent investigations and reports is that successful UVM programs must continually adapt to changing circumstances which means practices and procedures must be kept current. Why weaken this expectation in the standard? Also, I disagree with the elimination from the revised standard the present requirement R1 that all TVMPs include certain essential components (objectives, practices, approved procedures & work specifcations). Why make changes that imply TVMP's without these key components are acceptable?
Agree
I agree with the seperation and re-ordering of documenation and implementation requirements into two distinct groups. This is a welcome improvement to the standard.
Agree

Disagree
I disagree with the elimination of the present requirement R2 (last sentence) that requires a TO to have proper quality control (QC) systems and procedures in place to document & track planned UVM work so as to verify it was completed properly to work specifications. The need for this requirement was demonstrated as recently as last year when a grow-in outage occurred at BG&E due to a contractor trimming the wrong tree at the wrong location, a situation that could have been prevented with effective QC.
Agree
Disagree
The existing R1.4 is focused on identifying where vegetation clearance objectives cannot be met at the time UVM work is performed due to restrictions outside of the TO's immediate control. The proposed revised standard is focused on situations where work scheduled in the annual plan cannot be performed as planned for any reason. Can a constraint on planned work be internal such as budget related? Why bother with a corrective process for constrained planned work if the work not completed as planned poses no risk of causing an outage? I stongly believe that the sole focus of this provision must specifically address individual locations where, due to restrictions outside of the TO owner's control, vegetation clearances specified in the TVMP cannot be obtained. This section of the standard should be about trees being closer to conductors than they should be due to factors beyond the TO's control, rather than whether or not planned work was performed.
Disagree
I am strongly opposed to the removal of Clearance 1 from the standard. Being able to point to this provision has been invaluable to internal communications with upper management and external discussions with land owners and the public concerning UVM. In fact, other than the patrol/inspection requirements, no other provision in the standard has been as essential to preventing grow-in tree contacts than Clearance 1. It has forced TO's across the country to re-claim overgrown ROW and re-commit to consistent UVM practices. We all know how easy it is for TO's to get weak in the knees in the face of public opposition to proper and prudent UVM work even when it is clear what needs to be done. This dynamic is what led us to the 2003 blackout to begin with. I would like to see the drafting team consider expanding upon the existing model and create three clearances: 1. A clearance at the time work is performed, 2. An action threshold clearance which would trigger the TO would take immediate action to clear encroaching vegetation posing an unacceptable outage risk, and 3. A no closer than clearance in which vegetation would never be allowed to encroach in order to prevent flashover.
Disagree
If the standard continues to allow T.O.'s to design and implement their own TVMPs and expect them to use BMPs, ANSI A300, develop menthods and practices, adapt schedules and plans to changing conditions, etc., then it is reasonable to expect that T.O. personnel responsible for the TVMP to be experts in the field of utility vegetation management with appropriate training, certifications, licenses and credentials. I do not agree with eliminating this requirement. Quite the opposite, I believe that the requirement needs to be more specific as to minimum qualifications key personnel must meet. There are more requirements & qualifications to drive a semi-truck than to design and implement a program (UVM) critical to the operation of the nation's electric grid. Does that make sense?
Disagree
While I agree with the argument that the Gallet equatiion is a better technical or scientific method than IEEE 516 for determining realistic conductor to tree flashover distances, I do not agree that the new proposed clearance tables serve any useful purpose as a vegetation clearance standard from an operational perspective. The FAC-003-2 Technical Reference itself points to this fact when it states, "even if the exact size and shape of the C.C.Z. is known, it becomes nearly impossible in the field to correlate and accurately superimpose the C.C.Z. around the conductor." The Tech. Ref. goes on to say that "it is anticipated that many T.O.s will establish a work trigger well outside the C.C.Z." I agree wholeheartedly with that concept and believe that the Gallet clearance tables should be used by TO's to develop the more important "work trigger" or "action threshhold" clearances. This revision is overly focused on C.C.A.'s that have no practical operational application while being silent to the more critical to reliability issue of "work trigger/action threshold" clearances. This needs to be addressed if we hope to be successful at achieving the goal of zero preventable tree related outages.

Disagree
If T.O.'s are serious about public safety and potential electrical hazards or are required to comply with NESC/IEEE safety standards, then the greater, more conservative clearance distances must apply. On an complex issue where the aerial distances between live conductors and trees are dynamic and changing, I would prefer to be on the side of caution and on the side of safety. Given the history of cascading blackouts due to preventable tree contacts, there is a need to be conservative with the standards. I don't see it being in the public interest to argue that established minimum air insulation distances are inappropriately restrictive when applied to UVM.
No comment.
Agree
Disagree
It will be impossible for a T.O. to provide "evidence" that no encroachments of the C.C.Z. occured at any time during the year. This approach will be a compliance nightmare and is unworkable. How does one prove this never happens? You can't monitor every span of every line at all times. Obviously, whenever a T.O. has a preventable outage, that should be a violation. To address the issue of preventing outages before they occur and penalizing T.O.'s who don't take proper steps to prevent them, I prefer the approach of immediate removal of threatening vegetation that encroaches within a "threat trigger/action threshold" clearance distance per the T.O.'s formal imminent threat procedure. This "threat trigger/action threshold" clearance would be established by the T.O. and be a specific requirement under a revised FAC-003.
Agree
While being more specific & explicit, I don't interpret the overall requirement as being any different from the current standard.
Agree
While I very much respect the industry commitment and expertise of the drafting team members, the resulting revised standard reflects an effort to "revolutionize" the standard, when an "evolution" of the current standard would better serve the interests of system reliability. The kinds of wholesale changes proposed in this revision evoke real concerns about governmental regulations being a moving target and in many aspects, backs away from requirements that have led to real progress in UVM made since the 2003 blackout. For example, our company has invested tens of thousands of dollars and countless man-hours to comply with provisions of the existing standard only to see them simply done away with under the proposed revised standard. These investments were made based on an industry consensus standard as well as a realization that the requirements were reasonable and essential to improving system reliability. Where is the evidence that the current standard is not working as intended? What has changed in the last few years to warrant a complete re-write of the current standard? Most UVM professionals will agree there are some changes that need to be made to address FERC's concerns and to clarify intent. However, as presently written, I will recommend our T.O. vote against adoption of FAC-003-2.
Group
Western Area Power Administration, Upper Great Plains Region
Jerry Paulson
Western Area Power Administration, Upper Great Plains Region
Agree
Western (UGPR) agrees with the objective of using the FERC/NERC defined term "Bulk Electric System", but believe that the FERC/NERC definition includes lines above 100 kV. It needs to be clearly understood that use of the generic term in the Purpose section does not supersede the specific definitions (greater than 200 kV, etc.) contained in the Facilities section.
Agree
Western's (UGPR) agreement is contingent upon maintaining the requirements for consulting with Transmission Owners and neighboring Reliability Coordinator(s) and documenting the method for assessing the reliability significance of each included line as contained in R9 and R10.
Agree

A question that has surfaced during discussions within the industry is "Can the Transmission Owner designate an active R/W width that is less than the easement width even with a single-circuit line with no R/W set aside for vegetation buffer or future development?" OR, does the easement width equate to "Active T-Line ROW" under the situation described above.
Agree
Agree
Agree
The description of the annual plan now appears to require a detailed plan for each line. Under FAC-003-1, Western (UGPR) identified higher priority vegetation during aerial inspection and handled those expediciously. We then addressed a percentage of the lower priority trees based upon a number of agency defined factors (vegetation priority, ground conditions, resource availability, etc). The less rigid annual plan allowed us the freedom to cut the lower priority trees that made the best sense to cut. We are concerned that the additional rigidity will create a ever-changing annual plan because we may have to adjust dozens of lines based on inspections. We question whether it is prudent to occupy finite resources in continually modifying the annual plan when the real benefits accrue from actually performing the vegetation management activities.
Agree
Agree
Agree
While Western (UGPR) agrees with the removal of Clearance 1, we believe it is advantageous for Transmission Owners to have a "trigger distance" in order to have some additional time to plan and schedule vegetation work. The trigger distance is advantageous only if the Regulators do NOT interpret it to be an extended CCZ and do NOT enforce based on "trigger distance" instead of the CCZ.
Agree
Disagree
The CCZ as defined would very specifically outline a zone that needs to remain clear of vegetation to avoid a violation, but that specificity could be an overly burdensome concept to implement and/or monitor. Theoretically, there could be an infinite number of allowable vertical and horizontal (for outside phases) clearances depending on your location within each span. Theoretically, you may need to clear cut at mid-span (depending on retreatment intervals, growth rate, etc.) while allowing a 40 foot tree closer to the structure, along with everyting in between depending on your location within the span. To fully comply with the CCZ as defined, each Transmission Owner would have to have a table of allowable vertical and horizontal clearances for every few feet on every available span length within each line section. Producing such tables would be a significant burden to each Transmission Owner, but without them, the Transmission Owner could not verify that vegetation had not encroached within the CCZ. In order to produce the tables outlined above, the Transmission Owner would need to identify what design parameter(s) are applicable for the "correct" CCZ? We remain concerned that weather conditions in excess of those parameters could lead to a vegetation contact/outage and proving that weather conditions were in excess of design criteria would be extremely difficult or impossible for all spans on a lengthy transmission line. It is not uncommon to have weather stations 50 or more miles away from points on our transmission system. In order to certify/verify compliance, the Transmission Owner would have to physically take their table to the field and verify vertical and horizontal clearances from the edge of the theoretical envelope (not the actual conductor position) for all vegetation within the span. This would be a time-consuming, burdensome, cumbersome process if Regulators are going to require specific evidence in order for the Transmission Owner to document their annual certification.
Agree

Agree
Agree
Disagree
R4 as proposed would do nothing to improve the reliability of the BES. In fact, we believe that R4 (as currently proposed) would impose significantly more stringent requirements than most Transmission Owners have interpreted FAC-003-1 to require. We believe that if the proposed interpretation would have been offered under FAC-003-1 that there would have be a great backlash against that Standard. It is our believe that current annual certifications of compliance for FAC-003-1 by Transmission Owners don't use "any infringement of the CCZ by any piece of vegetation at any time" as their measure for compliance. It could be argued that this proposal would actually do more to curtail accurate reporting of potential violations. We believe that making an infringement into the CCZ a violation and having that violation carry a six (or seven) figure fine would do more to discourage accurate reporting than any other system under discussion. Making the Transmission Owner prove that an incursion into the CCZ didn't happen would force an inventory of every inch of the R/W which is a gigantic waste of resources. Being tasked with proving that something didn't happen could be compared with our justice system declaring suspects will be considered guilty until they are proven innocent. This is a flawed and blatantly unfair concept and not a productive way of attaining the Purpose stated in this document. Western (UGPR) is disappointed by the "zero tolerance" nature of this document and its interpretation that "any infringement of the CCZ by any piece of vegetation at any time" constitutes a violation. We are not aware of any other NERC standard that is zero tolerance and question why vegetation is singled out to bear the brunt when several other factors could contribute to a system cascading event (i.e. relay problems, system configuration, operator issues, etc). In summation, we believe that a zero tolerance document being applied with "guilty until proven innocent" principles would do much to create an increasingly adversarial relationship between regulators and the industry.
Agree
Agree
1) Proactive utilities are implementing policies that call for the removal of all vegetation that could grow into the CCZ. Such policies are not without resistance from landowners, environmental groups, etc. One of the arguments used by such groups is that NERC/FERC do not require removal of the trees. It would very helpful if this document included the practice of removing vegetation capable of encroaching within the CCZ as a reasonable or acceptable practice under this Standard. 2) We can forsee a possible public backlash if this Standard is adopted as written. We see many utilities needing rate increases to cover the additional costs of implementing and monitoring the more stringent requirements of this proposal. We also believe that the more stringent requirements will have no noticeable impact on reliability. So you'll have the public paying more and seeing no change in reliability and questioning why.
Group
SERC Vegetation Management Subcommittee (VMS)
Jack Gardner (Chairman) Joe Spencer (SERC staff)
SERC Reliability Corporation
Disagree
The definition of the Bulk Electric System generally does not include radial transmission lines directly serving load and, in addition, includes all lines operated at 100 kV and above. Use of the term Bulk Electric System will cause unnecessary confusion to the industry concerning applicability of this standard. Therefore, we recommend the continued use of the undefined term "electric transmission systems."
The SERC Vegetation Management Subcommittee (VMS) abstains on this question. However, we believe that this comment form should provide an option to abstain in addition to the options to agree/disagree.

Agree
Agree
Agree
While the SERC VMS agrees in general, there may be areas (i.e. desert terrain) where an annual interval would be unnecessary and not cost effective.
Agree
Disagree
The Requirement as written is too prescriptive and is open to interpretation, from an audit perspective, with use of the term â€œimmediateâ€□ communication and a partial list of activities. Many conditions or threats, requiring immediate removal, would not require communication with the Transmission Operator, who is not an applicable entity for this standard. The SERC VMS recommends that R1.4 be deleted. Since this is a "zero tolerance" standard any Transmission Owner will remove any discovered threats to prevent outages. If R1.4 is not deleted, the SERC VMS believes that imminent threats should be a defined term. The definition should be as follows: â€œImminent Threat: A vegetation condition which, if not addressed, will place a transmission line at a significant risk of a Sustained Outage.â€□
Agree
Agree
Agree
Disagree
The SERC VMS recommends that R2 be deleted. Since this is a "zero tolerance" standard any Transmission Owner will remove any discovered threats to prevent outages. While we agree that the implementation of an imminent threat procedure may be a valid concept, visualization of the Critical Clearance Zone (CCZ) and determining an approaching encroachment is a practice in application of theoretical conductor locations in real time.
Agree
Developing minimum sparkover distances in this standard is a superior approach for the stated reason in question 12. In addition, referring to tables and values in another standard is problematic if the referenced standard is revised and the tables are re-numbered or deleted altogether. We suggest that the tables based on the Gallet equations be removed from the standard and be kept in the technical white paper solely to assist in developing a common understanding of the threshold for taking actions.
Agree
See comments in #12 above.
Agree
Disagree
The concept of the CCZ is useful as a mental model to visualize required vegetation management work. While this is a good conceptual tool to drive consistent terminology and proper vegetation management practices, it remains theoretical in nature and impractical to measure on a span by span basis. The complexity of determining an encroachment into the CCZ is overly burdensome due to the need for survey accuracy measurements and engineering evaluations. In addition, this complexity leads to questions about the ability to audit this requirement. These complexities introduce reliability and audit issues when encroachments into this conceptual area are defined as violations. The SERC VMS believes the Sustained Outage, as defined by other measures in this standard, should be the non-compliance measure. We suggest that the CCZ concept be kept in the technical white paper and that all references to the CCZ be removed from the body of the standard.
Agree

Disagree
While the SERC VMS agrees in principle, we believe that the Requirement, as written, is â€œopen endedâ€☐ and could be interpreted to be in conflict with the "Active Rights of Way" concept. Clarifying the intent for the annual plan to focus on the Active Rights of Way will prevent incorrect interpretations. The SERC VMS suggest that the Requirement be reworded to read: â€œEach Transmission Owner shall implement its annual work plan for vegetation management within the Active Right of Way to accomplish the purpose of this standard within the extent of its easements and or legal rights.â€☐
Group
Progress Energy Florida
John Pinney
Transmission Operations and Planning Department
Disagree
The intent of the revision of the standard was to bring clarity to the standard. Referring to the BES in the purpose creates confusion as to the applicability of the standard. Therefore, Progress Energy recommends the continued use of the term "electric transmission systems."
Agree
While Progress Energy agrees that the RC is the appropriate entity, the drafting team should consider including a dispute resolution requirement for those instances when the Transmission Owner and the Reliability Coordinator disagree as to which lines below 200 kV should be included.
Agree
Disagree
The sub-requirements should be moved up to requirement level if the team desires to have different VRFs and VSLs.
Agree
Agree
Annual Plan should be a defined term in the standard. Without a definition, the term may be interpreted differently by industry and the regulator. The drafting team should raise the prominence of annual plan and define the attributes of an annual plan.
Disagree
Progress Energy agrees with the need for a Transmission Owner to have an Imminent Threat Procedure and that the Transmission Operator should be immediately notified of imminent threats but only when it is appropriate as defined by the TO's imminent threat procedure. We disagree with the requirement to immediately communicate with the Transmission Operator whenever the Critical Clearance Zone is approached. Not every scenario is an issue that requires action by the Transmission Operator: It is possible that the CCZ is being approached by vegetation at the lowest point of the CCZ whereas the conductor may be at its highest point in the CCZ (potentially 30 feet away from the vegetation) -- This typical situation does not merit notification to the Transmission Operator (which is required by FAC-003-2 as currently written).
Agree
Agree
Agree
Disagree
The Critical Clearance Zone as currently defined is too academic. Implementation of R2 would require field operations staff to determine the theoritical position of the line during inspections to decide

whether to engage the imminent threat procedures. The academic/theoretical aspects of the Critical Clearance Zone definition are not practical or enforceable. The criteria for a violation needs to be limited to the position of the conductor in real time.
Agree
Agree
Disagree
The standard has established a threshold of compliance. For consistency, compliance should be measured at the threshold not a Registered Entities program requirement.
Disagree
The definition of Critical Clearance Zone includes too many academic and theoretical elements. It is impossible to provide evidence that vegetation did not encroach into the the Critical Clearance Zone during TVMP cycles. Furthermore, the operations staff performing periodic ground and aerial inspections would need to determine the CCZ for each foot of transmission line to assure compliance with the standard as it is currently written. The CCZ concept can neither be implemented or enforced as written. The CCZ refers to Ratings which is defined in the Glossry of Terms as "The operational limits of a tranmsission system element under a set of specified condiditons." This definition is too broad to be a consistently enforceable term from one utilitly or region to the next. As it is currently written, no exemption exists for vegetation falling from outside the Active Transmission Line Right of Way into, or lodging in, the theoretical CCZ.
Agree
Agree
While Progress Energy agrees with the change, the term â€˜annual planâ€™ should be a defined term including threshold elements.
To avoid interpretation errors and provide clarity, the Applicability section for Facilities (4.2) of FAC-003 should include a statement that the standard only applies to vegetation within the Active Transmission Line Right of Way. For example, a fall-in from outside of the Active Transmission Line Right of Way that causes a sustained outage is not a violation of this standard. Any encroachment/outage initiated by vegetation falling from outside of the Active Transmission Line Right of Way should be excluded from violations. The CCZ concept is academically elegant, but when applied in the field, it presents significant implementation, interpretation and enforcement issues: the complexity of determining compliance could have the unintended negative consequences to reliability; removal of vegetation will likely be delayed because of the complexity and accuracy required to determine compliance prior to tree removal; certification that no violations have occurred will require lengthy and costly calculations and survey measurements; the standard refers to Ratings in the determination of line sags and Ratings is not a tightly defined term, PRC-023 requires relays to hold lines in beyond the line Ratings; how will PRC-023 requirements be factored into the CCZ concept. The CCZ concept introduces more complexity and ambiguity into the standard than it resolves. The drafting team needs to develop an alternative to the CCZ concept that is simple, easy to apply and clearly defines at what point a violation occurs. There are over 158,000 line miles of AC Transmission above 200kV in the United States, covering a Right of Way area potentially as large as 3,000 to 4,000 square miles (an area roughly equivalent to Rhode Island and Delaware combined). With billions of stems of managed vegetation, in and along the right of way, even six-sigma performance would result in a number of outages on a system this large. With countless VM processes and assessments that take place daily, it is unrealistic/unreasonable to expect zero-tolerance for random vegetation events (the transmission system is planned/operated to handle at least any single contingency).
Group
Kansas City Power & Light
Michael Gammon
Kansas City Power & Light
Disagree
The definition of the bulk electric system does not match the scope of the systems covered by the

vegetation management standard. If the term bulk electric system is used , it should exclude the areas not covered by the standard.
Agree
I agree with the qualification that the Reliability Coordinator identify sub-200kv facilities in consultation with its Transmission Owner(s) and neighboring Reliability Coordinator(s).
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Disagree
As proposed, Requirement R4 and corresponding Measure M4 will be highly subjective and impractical for the industry to implement. The determination of a violation due to encroachments into the Critical Clearance Zone will be subjective in nature due to field judgments, is random and not initiated by a known system event. It also will not be feasible for utilities to fulfill R4 requirements to ensure and provide evidence that any encroachments into Critical Clearance Zones have not occurred on their system throughout the year. Requirement R4 is not required since in the remaining requirements of FAC-003-2 contain the principal elements for compliance in ensuring the reliability of the bulk power system related to vegetation management of the transmission system. Specifically, the remaining requirements provide that a transmission vegetation plan be maintained, implemented and regularly reviewed whereby utilities must perform the requisite vegetation clearance work in order to prevent any sustained outages on the bulk power system. A sustained outage due to vegetation is a known, measurable event to which a penalty sanction will be invoked and therefore provides the required impetus for adherence to standard FAC-003-2. Requirement R4 and the associated measure M4 should therefore be removed from the proposed standard language.
Disagree
Exceptions should include flying debris including vegetation.
Agree
The title and explanation for Table 1 in Attachment 1 is not clear as to itâ€™s usage and applicability. It is being confused with the correlation with a minimum clearance and not as a component or building block of the Critical Clearance Zone. Under R10, there may be other methods for

consideration of assessing reliability significance of the sub-200 kV lines other than what is listed. Suggest the Drafting Team consider other criteria that an RC should condsider in its processes. R10.2 is redundant with R10.1. IROL by definition are those operating limits that represent instability, uncontrolled seperation or cascading. Suggest removing R10.2. Under M1.3 the measure requires the annual plan to cover a calendar year. An annual plan may cover a cycle growing season to growing season using the inspection to verify the next seasons work. Suggest removing the language for calendar year. M5, M6, M7 The measures should be requesting the evidence that it has violated the requirements. Good standing programs should not have to defend good practice by providing useless reports. The FAC-003-1 existing requirement R4 for reporting sustained outages is a reasonable and sustainable method that should be retained. R9 should include a periodic review period of annually. Any requirement to maintain current documentation should have a review period.
Individual
Chip Turner
Tampa Electric Company
Disagree
NERC glossary of terms defines the Bulk Electric System as "the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher." This, at a mimimum, could lead to confusion over what impacts the reliability of the Grid by potentially including facilities less than 200 kV.
Agree
Agree
Agree
Agree
Agree
Disagree
TECO aggres with the need for the Imminent Threat Procedure. However, the use of the new Critical Clearance Zone could create a "fill in the blank" standard. We we need to lock these clearances down as an industry so as to define what is an imminent threat and what the CCZ is in terms of specific distances.
Disagree
The phrasing above references a "corrective action plan". However, the standard as written is stated as an "interim corrective action process". These are not one and the same. Interim implies a truly temporary condition. As described on page 21 of the Technical reference, however,some of these operational issues may not be "interim".
Agree
Agree
While we agree with the removal of "fill-in the blank" requirements, we recommend the inclusion of professional qualifications for staff involved in this Standard. Reading the 42 page technical reference and the attached comment form, all involved need to really understand the Standard as well as industry practices.
Disagree
This is a good start. The Critical Clearance Zone (CCZ) is a very real and practical concept; however, it is not transferable to field conditions. This could result in a "fill in the blank" standard relative to what the Critical Clearance Zone will be in terms of distance. As I read this, it will be a sliding scale from insulator to mid span and back for each designated line voltage. The max wind speed to be used and other assumptions behind the determination of this zone may be as involved a Gallet's formula. This will lead to complications during operational inspection and verificaiton of these clearances.

Agree
Agree
Agree
Disagree
This is a good start. The Critical Clearance Zone (CCZ) is a very real and practical concept; however, it is not transferable to field conditions. This could result in a "fill in the blank" standard relative to what the Critical Clearance Zone will be in terms of distance. As I read this, it will be a sliding scale from insulator to mid span and back for each designated line voltage. The max wind speed to be used and other assumptions behind the determination of this zone may be as involved a Gallet's formula. This will lead to complications during operational inspection and verificaiton of these clearances.
Agree
Disagree
Good start. R8 must also address the flexability which is addressed in R1.3. As written, R8 does not do this. In addition, R8 states "within the extent of its easement and/or legal right...". This could create another set of conflicting criteria, where the utility has a long term "interim corrective action plan".
Good start. However, this will need additional work and reivew predicated on the above comments.
Individual
Edward Bedder
Orange and Rockland Utilities Inc.
Disagree
The use of the term "Bulk Electric System" (BES) could lead to confusion. In most regions BES includes lines with operating voltages equal to or greater than 100kV. The Standard is intended to apply to all lines with operating voltages equal to or greater than 200kV, and only those sub-200kV lines which are designated by the Reliability Coordinator (paragraph 4.2.1). Use of the words "electric transmission systems" rather than BES would eliminate this potential source of confusion.
Agree
Agree
Agree
Agree
Agree
Disagree
While we agree that the imminent threat procedure should be included in the TVMP, the requirement is overly prescriptive and should be revised to allow Transmission Owners flexibility to develop imminent threat procedures which best fit their systems and protocols. We recommend that R1.4 be reworded as follows: "Require a process or procedure for response to vegetation-related imminent threats to applicable lines. The imminent threat procedure shall require action to eliminate vegetation-related imminent threats, and shall be implemented upon discovery of such conditions". In addition, the definition of "Imminent Threat" should be defined. We suggest the following: "A condition which places a transmission line at significant risk of an outage in the very near term". An example of a vegetation-related imminent threat would be an uprooted tree leaning precariously toward a conductor which is certain to make contact with the conductor as the tree falls. Many Transmission Operators have imminent threat procedures in place to address all imminent threats to

their transmission systems, not just imminent threats due to vegetation. In many cases it would make sense for Transmission Owners to have one imminent threat process that covers all imminent threat conditions. The flexibility being recommended would facilitate this.
Agree
Agree
We generally agree, however please see comments included in question 18.
Agree
Disagree
While we agree that the imminent threat procedure should be implemented to address vegetation-related imminent threats as soon as they are identified, we believe that an "approach" of the CCZ should not be used to trigger implementation. The term "approached" does not identify a specific distance, so it is not clear to what extent vegetation would have to approach the CCZ in order to require implementation of the imminent threat process. This is left to the discretion of individual interpretation, is confusing to field personnel, and presents compliance and auditing problems. Imminent threats which are based on vegetation clearances should be identified based on specific clearances, not undefined approach distances. In practical field application the CCZ is an invisible area that changes shape and size along the length of the conductor. It is impossible to readily identify in the field without engineering calculations and precise measurements or the use of technology such as Aerial Laser Survey (ALS) using Light, Detection and Ranging (LIDAR) technology. Therefore under normal circumstances the location, size, and shape of the CCZ and vegetation encroachments of the CCZ can only be roughly estimated. Even with the use of ALS, which is relatively accurate, information is often not available for months after the survey flight. We believe that under normal circumstances imminent threats which are based on vegetation clearances should be identified in terms of specific distances from the conductor. While it is not possible for an inspector to readily identify a vegetation encroachment of the CCZ in the field, an inspector could more easily estimate a specified short distance between a conductor and vegetation in real time and initiate implementation of the imminent threat procedure based on that assessment. This assessment would be significantly more accurate than attempting to measure the distance between vegetation and the CCZ, which is not visible and constantly changes size and shape throughout the span. In cases where the Transmission Owner chooses to deploy ALS, the CCZ rather than the conductor could be used as the reference because in most cases the CCZ could be identified relative to approaching vegetation with a reliable degree of accuracy. Still a specific distance should be used to trigger implementation of the imminent threat procedure because of the issues previously raised with the use of the word "approached".
Agree
Agree
Agree
Disagree
We believe that R4 is not the most effective way to achieve the purpose of the Standard. As previously stated the CCZ and encroachments of it are generally not possible to identify in the field without taking precise measurements. The CCZ changes in size and shape continuously throughout each and every span. In many cases the CCZ can be very large, and the position of the conductor with respect to encroaching vegetation within the CCZ can be relatively far apart. Such cases would typically not be identified as encroachments of the CCZ by visual inspections. Only those instances where the vegetation is significantly overgrown would be readily identifiable. R4, as written presents a problem in terms of compliance, certification of compliance, and auditing because precise measurements of every span are impractical and costly to perform. Certification of compliance would require field personnel to spend valuable time estimating and attempting to measure potential encroachments of the CCZ. R4 does not provide incentive for Transmission Owners to deploy modern technology that is better able to identify encroachments of the CCZ with a reasonable amount of

accuracy, such as ALS and LIDAR which are described in the response to Question 11. In fact R4 might provide an incentive not to utilize this technology because Transmission Owners who identify encroachments using ALS which would otherwise not have been identified would be in violation of R4. Transmission Owners that choose to be less proactive often would not identify such encroachments and would be at less risk of violating R4. The effect could be less frequent use of ALS and other technology that may emerge. This would result in fewer problems being identified, a small percentage of which may not be discovered until they result in a line trip. We believe that the best way to achieve the purpose of this Standard is to encourage proactive behavior which prevents vegetation-related outages throughout the entire industry. R4 does not achieve this in the most effective way. We recommend the following: Eliminate encroachment of the CCZ as a violation of R4. Require Transmission Owners to immediately implement the imminent threat process defined in R1.4 when they identify instances where vegetation has grown within a specific distance as described in the response to Question 11 regarding R2. This would essentially combine R2 and R4. Require Transmission Owners to report to the Regional Entity any instances where the imminent threat process was implemented due to a vegetation-related clearance encroachment. This would add a reporting requirement for Transmission Owners. Require Regional Entities to perform additional audits of Transmission Owners that exceed metrics for vegetation-related clearance encroachments. The metrics should be established in the Standard based upon 1000 circuit miles of applicable lines. This would add an additional requirement for Regional Entites. Modify R5, R6, and R7 to include include preventing momentary outages as well as Sustained Outages. We believe that this concept would result in a more rigorous standard because of the additional requirements, but would focus the industry's attention in a more effective fashion. We believe it would result in fewer vegetation-related interruptions and a higher level of reliability soon after implementation, and would therefore best support the purpose of the Standard.
Agree
We agree, but recommend that momentary outages be included as violations of all three requirements as well. Also, the Standard does not directly require reporting of vegetation-related outages although implicitly, outages which are violations of the Standard must be reported. This has lead to some confusion during this comment phase and we suggest that the reporting requirements be directly stated in the Standard.
Agree
Clearance 1 has been eliminated from this draft. Version 2 as drafted only requires that Transmission Owners address vegetation that approaches the CCZ. This is essentially equivalent to Clearance 2 in version 1, a minimum clearance. Although unlikely this could result in some Transmission Owners adopting a just in time vegetation management concept that focuses on maintaining minimum clearances, rather than removing incompatible vegetation or achieving greater clearances. Although R1 requires Transmission Owners to design their TVMPs to control vegetation there is no clear requirement to address incompatible vegetation early and aggressively. The drafting team should revisit this and consider returning to some form of Clearance 1 or requiring the TVMP to address removal of incompatible vegetation within their easement rights
Individual
Jason Shaver
American Transmission Company
Disagree
ATC disagrees with changing the term "electric transmission systems" to "Bulk Electric System". This standard applies to 200 kV and higher transmission lines not all BES facilities. Suggested Purpose statement: To maintain the reliability of the electric transmission system by requiring entities to have and implement a transmission vegetation management plan.
Disagree
Requirements 9 and 10 should be deleted and replaced with the following language. Proposed Language The TO shall include those transmission lines below 200 kV that that are associated with an established IROL. (This language could either be uses as a requirement or inserted into the Applicability section.) Our statement provides a clear decision on which lower voltage lines have to be included in an entities transmission vegetation management program.

Agree
We agree with the idea but the term "active transmission facilities" needs additional clarity. This clarity could be accomplished with a footnote. Proposed Footnote: A transmission facility that contains a transmission line to which FAC-003 is applicable. The proposed footnote aids in the indentification of applicable transmission facilities.
Agree
Agree
We agree with a minimum inspection frequency, but believe that the additional verbiage "â€¦ that takes into account local and environmental factors" should be deleted. The additional verbiage does not provide greater reliability only more documentation. Proposed Language: Specify a vegetation inspection frequency of at least once per calendar year.
Agree
ATC agrees with separating the implementation Requirements from the Annual Plan Requirements.
Disagree
We agree that entities should have a Vegetation Imminent Threat Procedure, but that the term should be defined. Also see related comments to Question #11.
Agree
ATC agrees with the concept but disagrees with the proposed language. ATC believes the term "interim" should be removed from R 1.5. In some cases, a corrective action can end up being a long term/normal fix. Proposed Language: Specify a corrective action process that will be used when estabilshed clearances or methodologies are altered.
Agree
Agree
Disagree
ATC believes that the Critical Clearance Zone (CCZ) is a good theoretical concept to aid industy in understanding the overall movement of conductors, but it is an impractical concept for field application. Due to the variability in the size of the CCZ as you move along a conductor, as well as changes from span to span or even line to line due to design parameters, loading or weather-related issues, the CCZ concept should not be tied to an imminent threat procedure. Vegetation approaching the CCZ does not constitute an imminent threat. It may be months to years before this vegetation ever gets to a proximity distance from the conductor to be within a "spark-over" distance as defined by the Gallet equations. Requirement R2 should support the purpose of this standard by requiring implementation of the Vegetation Imminent Threat Procedure when the Transmission Owner has visual, field knowledge that vegetation is encroaching upon a conductor within some specific distance that is a multiple of the Gallet distances referenced in Table I of FAC-003-2 (to be conservative we suggest two to three times the Gallet distances). Failure to implement the Vegetation Imminent Threat Procedure in such instances would be a violation of R2. As R2 is currently written, a Transmission Owner cannot comply with R2 unless the imminent threat procedure is continuously being implemented or monitored, because vegetation that is growing is always approaching the CCZ. "Approaching the CCZ" cannot be the trigger for implementation of the Vegetation Imminent threat Procedure. Instead, the trigger should be an encroachment within some observed field distance. Requirement R2 could be rewritten as follows: â€œEach Transmission Owner shall implement its Vegetation Imminent Threat Procedure when the Transmission Owner has knowledge, obtained through normal operating practices or notification from others, that vegetation is encroaching upon a conductor within a distance that is twice the Gallet clearance distances referenced in Table I." Using a multiple of the Gallet distances provides a safety factor. Assessing a violation for failure to appropriately implement the Vegetation Imminent Threat Procedure or for a sustained vegetation-related outage would promote the proper behavior.
Agree

Disagree
While the CCZ is valuable to understanding the movement of conductors, it cannot be readily applied in the field. This field application challenge is noted in the Technical Reference Document (pages 29 & 30). The way R4 is currently stated, the Transmission Owner would be in violation of R4 for any CCZ encroachment not due to natural disasters or human or animal activity. This would include a tree falling from outside the right of way corridor that passes through the theoretical CCZ. Furthermore, Transmission Owners would be required to self-certify compliance with R4, and ATC does not think there is a practical way to do that. Clearly, the approach of assessing violations for CCZ encroachment is unworkable. ATC believes that R4 should be deleted.
Agree
Agree
ATC agrees with the requirement to implement the annual work plan, but recommends striking the words "within the extent of its easement and/or legal rights". The emphasis for this requirement is to execute the annual work plan. The white paper already speaks to the point that it is a best practice for utilities to exercise their legal rights. If we agree that the goal is to prevent outages, then we can simply end this requirement with "implement its annual work plan for vegetation management." Propose Changes to R8: Each Transmission Owner shall implement its annual work plan for vegetation management.
FAC-003-1 lacks clarity that is essential for understanding what is necessary for compliance. The proposed FAC-003-2 needs to be simplified to aid with field implementation and compliance interpretation. Currently, it does not provide the clarity and simplification needed by Transmission Owners and regulatory bodies to enhance reliability. Requirement 1.3: The proposed requirement does not allow enough flexibility for making changes to the Annual Plan. We believe that changes to the Annual Plan should be allowed even if that means delaying something until the next Annual Plan. Our Proposed Changes: Have an annual plan that identifies the applicable lines to be maintained and associated work to be performed. Adjustments to the annual plan are permissible. We believe that our proposed language accomplishes the SDT's intent while allowing for appropriate flexibility.
Group
Western Area Power Administration, Rocky Mountain Region
Ron Turley
Western Area Power Administration, Rocky Mountain Region
Disagree
Use of the general term Bulk Electrical System creates unintentional confusion regarding the applicability of this standard to lines operated at 200 kV or higher and designated lines operated below 200 kV.
Agree
Agree
Agree
Disagree
Some areas such as highly developed urban areas, deserts, or grassland prairie may not be conducive to tall vegetation growth and require frequent (annual) inspection.
Agree
Agree
The Technical Reference document could be expanded to explain that a well rounded Imminent Threat Procedure should contain many mitigation alternatives to appropriately address a wide range of field situations, including a "no immediate field action is required" option. For example, further investigation of a potential imminent threat situation may reveal that the situation has been

erroneously reported or incorrectly measured and therefore no immediate vegetation removal actions are required. A utility's Imminent Threat Procedure may also address situations beyond just vegetation related incidents.
The specifics of a "plan" as required by R1.4 in version 1 of the Standards has been replaced with the generalities of a "process" required by R1.5 in version 2 of the Standards. At the time of an audit, the adequacy of a general process is harder to measure than the adequacy of the specific mitigation measures that were previously required by R1.4 in version 1 of the Standards. It is unclear what an auditor will be looking for to determine compliance with R1.5 - will the auditor be looking for generalities or specifics? Further, if a utility has documented their interim corrective action process, but it is not followed, is this a violation of the Standards?
Agree
Agree
Disagree
As discussed in the Technical Reference document, the CCZ is a complicated theoretical envelope surrounding all rated operating positions of the conductor. Its dynamic shape is constantly changing and is contingent upon location within the span. Calculation of the size and shape of CCZ is based, in part, upon the design parameters of the transmission facility. However, as-built or long term maintenance conditions can often diverge from the original design requirements over time. Ground elevations can also change as a result of man made or natural causes from the original design elevations recorded on plan and profile engineering drawings. Consequently, precise field measurement of the as-built CCZ is extremely problematic and strategies that utilize the calculation of allowable right-of-way tree heights can be hindered by unrecorded deviations from the original design criteria. Allowable tree height strategies also become increasingly more difficult and impractical with increasing extremes in terrain. While the CCZ is a very important concept for an effective vegetation management program it is far to theoretical, dynamic, and impractical to field measure for use as a clear and precise boundary for regulatory purposes. In addition, the R2 requirement for action when the imprecise and theoretical CCZ boundary is "approached" by vegetation is an even more subjective and unmeasurable. The "rate of approach" is really the key issue of concern. The rate of vegetation approach is a function of many variables including species type and site specific growing conditions. For example, a Century Plant which can grow six inches a day is obviously a much greater concern than a Lodgepole Pine on a dry mountain top which grows only a few inches a year. As such, there is no practical way to define or measure for regulatory purposes those "approach" situations that legitimately require immediate action from those "approach" situations that do not. The wording and concepts of R2 are therefore to imprecise to be used as clear requirements for Standards compliance.
Agree
Agree
Agree
Disagree
As discussed in the Technical Reference document and question #11 above, the CCZ is a complicated theoretical envelope surrounding all rated operating positions of the conductor. Its dynamic shape is constantly changing and is contingent upon location within the span. Calculation of the size and shape of CCZ is based, in part, upon the design parameters of the transmission facility. However, as-built or long term maintenance conditions can often diverge from the original design requirements over time. Ground elevations can also change as a result of man made or natural causes from the original design elevations recorded on plan and profile engineering drawings. Consequently, accurate field measurement of the as-built CCZ is extremely problematic and strategies that utilize the calculation of allowable right-of-way tree heights can be hindered by unrecorded deviations from the original design criteria. Allowable tree height strategies also become increasingly more difficult and impractical with increasing extremes in terrain. While the CCZ is a very important concept for an

effective vegetation management program it is far to theoretical, dynamic, and impractical to field measure for use as a clear and precise boundary for regulatory purposes. As such, R4 as written should be deleted from the Standards. Further, the requirement to provide evidence of something that has not occurred (no vegetation encroachments of the CCZ) is also impractical. General industry interpretation of R1.2.2 in version 1 of the Standards is that the specific Clearance 2 distance is the precise boundary that is not to be encroached verses the broader area that is ultimately mapped out as the conductor moves through "all rated electrical operating conditions". Only the Clearance 2 distance value is a clear, precise number that can be accurately observed and measured in the field. If there is a persistence to retain the CCZ concept as a requirement within the Standards, the second bullet option above regarding the initiation of the imminent threat process upon discovery of a possible encroachment is the preferred option. Since a potential encroachment into the CCZ is not a violation under this option, exact determination of the CCZ boundary is no longer as essential. Rather, the focus is on triggering mitigation to vegetation problems to prevent outages. However, as with question #11 above, there is still no practical way to determine for regulatory purposes those "potential encroachment" situations that legitimately require initiation of the imminent threat process from those "potential encroachment" situations that do not. Under this option the utility is really motivated to initiate the imminent threat process to avoid an impending outage. As such, the occurrence of an outage becomes the only clear, precise and observable means to determine a Standards violation. A proposed alternative to ensure a level of reliability equal to or better than FAC-003-1 is to retain the Clearance 2 requirement (without the imprecise "all rated electrical operating conditions" language) in combination with the sustained outage requirements of R5, R6 and R7. If an additional margin of safety is determined to be required, industry performance can be adjusted to become more proactive by increasing the minimum Clearance 2 distance to a value greater than the proposed version 2 Gallet equation (table 1) values. Thinking in terms of the CCZ concept, it is obvious that a larger Clearance 2 value translates into a larger CCZ envelope. A larger CCZ envelope in turn triggers mitigation for possible CCZ encroachments sooner.
Agree
Agree
1. Further clarification of the definition of the active right-of-way appears to be required. For example, if a tree falls from an area controlled by the utility which is outside of the normal width of the actively managed right-of-way, but this area is not reserved or "intended for other facilities", could this be a violation of a Standards requirement? The narrative discussion within the white paper seems to imply that it is not, but the "intended for other facilities" requirement within Standards definition implies that it would be. 2. As currently presented, FAC-003-2 requires an impractical and unrealistic level of performance from the industry. This level of performance is unwarranted for the overwhelming number and expanse of transmission facilities to which the Standards are applicable. Many of these facilities, such as radial load lines, are not critical TOT or IROL facilities and have a minimal impact on overall grid reliability. The rigorous zero tolerance level of performance is only warranted for those lines that are critical TOT or IROL facilities. 3. The Standards should clearly identify any and all reporting requirements.
Individual
test
test
Agree
Disagree
Agree

Individual
Alice Druffel
Xcel Energy
Agree
Disagree
We propose adding the following language to the end of the definition for "Active Transmission Line Right of Way": OR OTHER PURPOSES, REGARDLESS OF THE PREMISES DIMENSIONS IN ANY EASEMENT, LICENSE AGREEMENT OR OTHER LAND RIGHT DOCUMENT.
Disagree
Add a note of exception to the requirement for inspections on those lines that do not have vegetation management issues (e.g. lines that traverse desert areas only).
Disagree
The way this requirement is written may require a utility to prove a negative. In other words, prove that we did not have trees encroaching into the CCZ at any time. This is impossible to prove. We propose the following language: â€œThe TO shall not have a encroachment within the CCZ which was not dealt with by utilizing the imminent threat procedure before experiencing a Sustained Outage, with the following exceptions 1) Encroachment of the CCZ that result for natural disasters 2) Encroachment of the CCZ that result from human or animal activity."
Agree
We agree, however please add a reference to â€œwind gusts 45 miles per hour or greaterâ€□ to the exception note for this requirement. The exception would read â€œ1) Sustained Outages of transmission lines that result from sustained winds (45 miles per hour or greater) or gusts due to natural disasters.â€□
Attachment 1, Table I- Change the title of the table from "Proposed Minimum Vegetation Clearance Distances" to "Critical Clearance Zone Distances". The reason being is that the general public could

interpret this table to mean that this is all the clearance that is required by a utility at the time of pruning. Section C, Violation Severity Levels- There is some inconsistency between the C.2 chart and the contents of the Standard and the White Paper. For example, the White Paper specifies that an exception to an R6 blowing together violation would exist for sustained winds of gusts of 45 miles per hour or greater. As to R7, the Standard itself notes that a violation only occurs if the vegetation falling into the line is from within the ROW â€“ C 2 does not incorporate that requirement. There are two approaches: either note the exemptions within the C 2 chart, or add a footnote to the chart along these lines: "This chart summarizes various provisions, the details of which are more fully set forth in the Standard and White Paperâ€□. We would recommend the later approach. General suggestions: 1) It appears that the FAC-003 Standard is the only "zero tolerance" standard, in some respects. Is this reasonable? 2) There appears to be "advisory" language in this version of the Standard. This type of language should be part of the White Paper, not the Standard itself. 3) Utilities need more support from FERC to deal with regional roadblocks within the USFS regarding the implementation of IVM. The Memorandum of Understanding is not universally accepted within all regions of the USFS.
Individual
Jeff Hackman
Ameren
Disagree
By definition, the capitilized term, Bulk Electric System, is defined to include most facilities 100 kV and above. The previous version of this standard appropriately restricted the applicability of the standard to those facilities operating above 200kV and any additional facilites identified by the Regional Reliability Organization as critical. This new version of the standards attempts to limit the 100-200 kV class applicability by having the RC identify the critical facilities. We believe the change creates unnecessary and undesirable confusion in that one requirement of the standard says that it applies to all the BES and then another requirement limits the application. Leaving the term "electric transmission systems" in the definition is preferable to that proposed.
Disagree
While the RC would seemingly have the wide area view to make the assignment appropriate, the standard is really trying to determine the entity who can assess the risk to the BES of a vegetation-related outage. The management of that risk is in the venue of the Transmission Planner who, in the long term, designs the system and, in the Operating Horizon, establishes the parameters of operation that will lead to reliability. Certainly, the RC is preferable to the RE (RRO). However, the TP is preferable to the RC.
Agree
Agree
This is a good change from a compliance perspective; the documentation requirements can now be assigned lower VRFs than the implementation requirements
Agree
Agree
Disagree
Transmission Owners should have a Vegetation Imminent Threat Procedure, and "Vegetation Imminent Threat" should be a defined term, defined as: "Vegetation observed in the field encroaching upon a conductor within a distance defined in the Vegetation Management plan." In this case, the threat would require an immediate response and would include communication to the Transmission Operator. From there, the actions that the operator decides to take will be dependent on the incident and system conditions. We do not need to be prescriptive with this requirement but rather allow the Transmission Operator and appropriate field personnel the flexibility to make the right decisions to safely, promptly and appropriately remove the vegetation threat. From a Transmission Owner's perspective, many situations can constitute an imminent threat but this approach will clearly define a "Vegetation Imminent Threat" as it relates to the Purpose of this standard. While a definition of "Vegetation Imminent Threat - Vegetation observed in the field encroaching upon a conductor within

a distance that is twice the Gallet clearance distances referenced in Table I of the draft standard FAC-003-2" would be acceptable and far superior to that which is proposed, it will still be difficult for field personnel to identify, at each foot of a transmission circuit, wherein twice the Gallet distance would be found. See comment on #11 below.
Agree
Agree
Agree
Disagree
The CCZ is a good theoretical concept to aid industy in understanding the overall movement of conductors, but it is an impractical concept for field application. Due to the variability in the size of the CCZ as you move along a conductor, as well as changes from span to span or even line to line due to design parameters, loading or weather-related issues, the CCZ concept should not be tied to an imminent threat procedure. Vegetation "approaching" the CCZ does not constitute an imminent threat. In fact, the moment after vegetation is cut, it begins again to "approach" this zone. It may be months to years before this vegetation ever gets to a proximity distance from the conductor to be within a "spark-over" distance as defined by the Gallet equations. Requirement R2 should support the purpose of this standard by requiring implementation of the Vegetation Imminent Threat Procedure when the Transmission Owner has visual, field knowledge that vegetation is encroaching upon a conductor within some specific distance. As R2 is currently stated, a Transmission Owner cannot comply with R2 unless the imminent threat procedure is continuously being implemented, because vegetation that is growing is always approaching the CCZ. "Approaching the CCZ" cannot be the trigger for implementation of the Vegetation Imminent threat Procedure. Instead, the trigger should be an encroachment within some observed field distance.
Agree
Agree
Agree
Disagree
The second bulleted alternative above is the best approach, but it should be improved by changing the imminent threat trigger from "encroachment of the CCZ" to "encroachment within some observed, field distance that is defined in the Plan. This would allow Transmission Owners to define for field personnel a CCZ that accomplishes some multiple of the Gallet distances referenced in Table I" but is easy to determine and apply. We have recommended changes to accomplish this in Requirement R2 (see our response to Question #11 above), and R4 should simply be deleted. While the CCZ is valuable to understanding the movement of conductors, it cannot be readily applied in the field. This field application challenge is noted in the Technical Reference Document (pages 29 & 30). The way R4 is currently stated, the Transmission Owner would be in violation of R4 for any CCZ encroachment not due to natural disasters or human or animal activity. This would include a tree falling from outside the right of way corridor that passes through the theoretical CCZ. Furthermore, Transmission Owners would be required to self-certify compliance with R4, and we don't think there's any way to do that. Clearly the approach of assessing violations for CCZ encroachment is unworkable. Likewise, the third alternative listed above is untenable. The tiered approach could have a mitigating effect on violations, but it would require the same inspection effort and postponement of vegetation management that makes the first alternative unworkable. Both the first and third alternatives would require very significant additional expenditures for surveys and documentation in an impossible attempt to certify compliance - money that would be better spent controlling vegetation.
Agree
Agree

We recommend striking, or modifying, the words "within the extent of its easement and/or legal rights" as they may be introducing an unintended compliance quagmire. For example, if the easement is extraordinarily wide but reliability and the work plan do not dictate that the work plan apply to the entire easement, how will compliance be measured? The work plan should recognize easement or legal rights issue. Therefore, the emphasis for this requirement shoudl be to execute the annual work plan. The white paper already speaks to the point that it is a best practice for utilities to exercise their legal rights. By tagging the words on to the requirement, we are adding unnecessary compliance validation to this requirement for both industry and the regulators. If a clarifying sentence is required, we would suggest that R8 stop with the word standard and a new sentence be added, "The work plan should address easement or legal/rights"
While FAC-003-1 lacks clarity that is essential for understanding what is necessary for compliance, the proposed FAC-003-2 needs to be simplified to aid with field implementation and compliance interpretation. Currently, it does not provide the clarity and simplicity needed by Transmission Owners to implement and regulatory bodies to monitor in a manner that will enhance reliability.
Individual
John Humphrey
Nebraska Public Power District
Disagree
NPPD disagrees with the change to bulk electric system, because it creates confusion on the applicability. This standard only applies to certain lines and not the entire (bulk) system.
Agree
NPPD agrees that the Reliability Coordinator is the correct body for identification of any sub 200kV lines that would be subject to this standard.
Agree
Agree
Agree
Agree
Disagree
NPPD agrees that a Transmission Owner should have an imminent threat procedure and the TO be immediately notified of any threats. NPPD disagrees with prescribing what needs to be done as a result of the threat. This is condition based and staff can make the right decision as to what corrective actions are necessary.
Agree
Agree
Agree
Disagree
The CCZ is a good concept to explain the flight path of a conductor under all conditions but it would be impractical to use in the field. There are too many variables to consider and an encroachment does not constitute an immediate threat.
Agree
Agree
Agree

Disagree
NPPD disagree with an encroachment being a violation. A lot of time would need to be spent to determine if an encroachment occured and in a self regulating environment, reporting would be miminal if any. The Transmission Owner would be in violation for any non natural event. Even a tree falling into the ROW passing through CCZ would be in voilation of R4. Difficult at best to enforce. We need to spend time keeping the ROW cleared and less time inspecting for possible encroachments.
Agree
Agree
Group
Progress Energy Carolinas
Jack Gardner
Transmission Operations and Planning Department
Disagree
The intent of the revision of the standard was to bring clarity to the standard. Referring to the BES in the purpose creates confusion as to the applicability of the standard. Therefore, Progress Energy recommends the continued use of the term "electric transmission systems."
Agree
While Progress Energy agrees that the RC is the appropriate entity, the drafting team should consider including a dispute resolution requirement for those instances when the Transmission Owner and the Reliability Coordinator disagree as to which lines below 200 kV should be included.
Agree
Disagree
The sub-requirements should be moved up to requirement level if the team desires to have different VRFs and VSLs.
Agree
Agree
Annual Plan should be a defined term in the standard. Without a definition, the term may be interpreted differently by industry and the regulator. The drafting team should raise the prominence of annual plan and define the attributes of an annual plan.
Disagree
Progress Energy agrees with the need for a Transmission Owner to have an Imminent Threat Procedure and that the Transmission Operator should be immediately notified of imminent threats but only when it is appropriate as defined by the TO's imminent threat procedure. We disagree with the requirement to immediately communicate with the Transmission Operator whenever the Critical Clearance Zone is approached. Not every scenario is an issue that requires action by the Transmission Operator: It is possible that the CCZ is being approached by vegetation at the lowest point of the CCZ whereas the conductor may be at its highest point in the CCZ (potentially 30 feet away from the vegetation) -- This typical situation does not merit notification to the Transmission Operator (which is required by FAC-003-2 as currently written).
Agree
Agree
Agree

Disagree
The Critical Clearance Zone as currently defined is too academic. Implementation of R2 would require field operations staff to determine the theoritical position of the line during inspections to decide whether to engage the imminent threat procedures. The academic/theoretical aspects of the Critical Clearance Zone definition are not practical or enforceable. The criteria for a violation needs to be limited to the position of the conductor in real time.
Agree
Agree
Disagree
The standard has established a threshold of compliance. For consistency, compliance should be measured at the threshold not a Registered Entities program requirement.
Disagree
The definition of Critical Clearance Zone includes too many academic and theoretical elements. It is impossible to provide evidence that vegetation did not encroach into the the Critical Clearance Zone during TVMP cycles. Furthermore, the operations staff performing periodic ground and aerial inspections would need to determine the CCZ for each foot of transmission line to assure compliance with the standard as it is currently written. The CCZ concept can neither be implemented or enforced as written. The CCZ refers to Ratings which is defined in the Glossry of Terms as "The operational limits of a tranmsission system element under a set of specified condiditons." This definition is too broad to be a consistently enforceable term from one utilitly or region to the next. As it is currently written, no exemption exists for vegetation falling from outside the Active Transmission Line Right of Way into, or lodging in, the theoretical CCZ.
Agree
Agree
To avoid interpretation errors and provide clarity, the Applicability section for Facilities (4.2) of FAC-003 should include a statement that the standard only applies to vegetation within the Active Transmission Line Right of Way. For example, a fall-in from outside of the Active Transmission Line Right of Way that causes a sustained outage is not a violation of this standard. Any encroachment/outage initiated by vegetation falling from outside of the Active Transmission Line Right of Way should be excluded from violations. The CCZ concept is academically elegant, but when applied in the field, it presents significant implementation, interpretation and enforcement issues: the complexity of determining compliance could have the unintended negative consequences to reliability; removal of vegetation will likely be delayed because of the complexity and accuracy required to determine compliance prior to tree removal; certification that no violations have occurred will require lengthy and costly calculations and survey measurements; the standard refers to Ratings in the determination of line sags and Ratings is not a tightly defined term, PRC-023 requires relays to hold lines in beyond the line Ratings; how will PRC-023 requirements be factored into the CCZ concept. The CCZ concept introduces more complexity and ambiguity into the standard than it resolves. The drafting team needs to develop an alternative to the CCZ concept that is simple, easy to apply and clearly defines at what point a violation occurs. There are over 158,000 line miles of AC Transmission above 200kV in the United States, covering a Right of Way area potentially as large as 3,000 to 4,000 square miles (an area roughly equivalent to Rhode Island and Delaware combined). With billions of stems of managed vegetation, in and along the right of way, even six-sigma performance would result in a number of outages on a system this large. With countless VM processes and assessments that take place daily, it is unrealistic/unreasonable to expect zero-tolerance for random vegetation events (the transmission system is planned/operated to handle at least any single contingency).
Group
Southern California Edison Company
Samuel Stonerock
Transmission / Distribution Business Unit

Agree
Q1: SCE agrees in part with the proposed revisions to the purpose statement. However, we believe the phrase "vegetation related outages" is unnecessarily vague. Based on the content of certain requirements in Version 2, the intent of this standard is and should be to prevent sustained outages due to vegetation-to-line contacts. SCE respectfully suggests the purpose statement (A3) be revised to read: "To improve the reliability of the Bulk Electric System by preventing vegetation-to-line contacts that could lead to Cascading.â€□
Agree
Q2: No comments.
Agree
Q3: No Comments.
Disagree
Q4: SCE does not agree with separating the documentation and implementation aspects of the TVMP into separate requirements R3 and R8 (respectively). SCE believes that proposed R3 and corresponding M3 should be eliminated and replaced with a modified version of proposed R8. SCE respectfully suggests that proposed R8 be revised to read: "Each Transmission Owner shall implement and follow its Vegetation Management Program to the extent allowed by existing easement and/or legal rights."
Disagree
Q5: SCE does not agree with imposing a one-size-fits-all inspection frequency of â€œat least once per calendar yearâ€□ upon all U.S. Transmission Owners. The associated technical paper presents no credible evidence or statistical corroboration to support the proposed inspection frequency. Until such time as a thorough industry study or similar evidence is presented that demonstrates the proposed inspection frequency is cost effective and will enhance system reliability, Transmission Owners should be allowed to establish their own inspection frequency rate. Regarding the enforcement of a non-standardized inspection frequency, should a Transmission Owner incur a vegetation-to-line contact that results in a Sustained Outage, upon review of the investigation results, the responsible Reliability Coordinator and/or NERC could then impose a more stringent inspection frequency requirement upon the infracting Transmission Owner. The imposition of more stringent inspection frequencies could be applied on a temporary or permanent basis, depending on the severity of the outage, but lacking a demonstrated need, good performing Transmission Owners should be allowed to establish their own inspection frequencies based upon their individual needs and operating conditions. SCE respectfully suggests R1.2 be revised to read: "Specify a vegetation inspection frequency that takes into account local and environmental factors."
Agree
Q6: SCE agrees in part. Proposal R1.3, requiring Transmission Owners to establish an annual maintenance plan is generally acceptable. However, SCE disagrees with including peripheral information in R1.3 and the institution of a separate implementation requirement (R8). Further, we note that some portions of FAC-003-1 (R2) appear to have been transplanted into proposed R1.3 and that the word â€œshallâ€□ has been replaced with the word â€œshouldâ€□. SCE believes that inserting the word â€œshallâ€□ into statements that are clearly advisory in nature does not necessarily create enforceable requirements. As proposed, an enforcement auditor might incorrectly determine that the new â€œrequirementâ€□ statements in proposed R1.3, describing the need for â€œflexibilityâ€□, â€œconsideration of permitting and scheduling requirementsâ€□, and self-determined â€œmethodologiesâ€□ is a comprehensive list of items for the maintenance plan. Because this list of program elements is not complete, SCE recommends all text following the opening sentence be removed from R1.3 and inserted into the supporting technical paper. SCE respectfully suggests that R1.3 be revised to read: "Specifies a plan that identifies the applicable lines to be maintained and associated work to be performed."
Agree
Q7: SCE agrees in part with the content of R1.4 because of its similarity to existing requirement R1.5 in FAC-003-1. However, we disagree with the drafterâ€™s inclusion of peripheral information following the first sentence. We also note that the second sentence of proposed R1.4 includes both a requirement and a recommendation. SCE believes this and similar recommendations are best suited for the supporting technical paper. SCE respectfully suggests that R1.4 be revised to read: "Specify a

process or procedure for communicating an impending vegetation-to-line contact that may result in a sustained outage and the appropriate response measures.â€☐
Agree
Q8: SCE agrees in part with the revisions to R1.5, including the proposed phrase "corrective action process". However, we do not believe it is necessary to include the term "Transmission Owner" in the sentence because the entire standard is clearly applicable to Transmission Owners. SCE respectfully suggests that proposed R1.5 be revised to read: "Specify an interim corrective action process for use when planned vegetation maintenance is deterred."
Agree
Q9: No comments.
Agree
Q10: No comments.
Agree
Q11: SCE agrees in part with proposed R2. The use of the Gallet equation and the replacement of the existing Clearance 2 requirement with the Critical Clearance Zone is acceptable. However, SCE strongly disagrees with establishing a separate requirement for implementing an imminent threat procedure should there be an encroachment of the Critical Clearance Zone because it forms the basis of an unnecessary zero-tolerance enforcement policy. Read in context with corresponding Measure 2, R2 appears to require Transmission Owners to prove that a Critical Clearance Zone encroachment did or did not occur and also prove that that an imminent threat procedure was or was not properly invoked. Although SCE agrees that CCZ encroachments should be addressed timely, we disagree with the notion and underlying assumption that a CCZ incursion will always lead to a flash-over or a vegetation-to-line contact. If the goal of FAC-003-2 is to prevent sustained outages (due to vegetation-to-line contacts) that could lead to Cascading, emphasizing â€œpreventionâ€☐ is understandable, however, enforcing prevention measures is an entirely different matter. Under the proposed requirements, a vegetation-to-line contact could conceivably represent two distinct violations of FAC-003-2. SCE believes this type of regulatory double jeopardy is patently unfair and forcing Transmission Owners to prove a CCZ encroachment did or did not occur is equally unfair and unenforceable. Because R1.4 adequately addresses the Transmission Ownerâ€™s responsibility regarding the implementation of an imminent threat procedure, SCE respectfully recommends that proposed R2 and corresponding M2 be removed from FAC-003-2.
Agree
Q12: No comments.
Agree
Q13: No comments.
Disagree
Q14: SCE does not agree with the inclusion of proposed R3 and believes it should be replaced with a modified version of proposed R8. SCE respectfully suggests that proposed R8 be revised to read: "Each Transmission Owner shall implement and follow its Vegetation Management Program to the extent allowed by existing easement and/or legal rights."
Disagree
Q15: SCE does not agree that proposed R4 was written in the most effective way because it establishes a zero tolerance enforcement policy. SCE agrees that a CCZ incursion should be addressed promptly, but we do not agree that a CCZ incursion is equivalent to a vegetation-to-line contact, or that a CCZ incursion represents an imminent threat of flash-over. As written, proposed R4 would require Transmission Owners to prove that a Critical Clearance Zone incursion has not occurred. Short of a daily ground or aerial inspection of every applicable transmission line, it is clearly impossible for a Transmission Owner to monitor their active Right of Way on a 24/7/365 basis to ensure a CCZ incursion will not or has not occurred. Bearing in mind that even the most robust of Transmission VM programs may occasionally identify an anomalous condition (in or outside the active ROW) that left untreated could lead to a flash-over or vegetation-to-line contact, the identification of such conditions typically occur during scheduled aerial or ground patrols and addressed timely. Of the two alternatives offered, SCE finds the first option (second bullet item) to be the most palatable. However, even that option leaves significant doubt as to practical enforcement, because a Transmission Owner could still be found in violation of two separate requirements (R4 and R5, R4 and R6 or R4 and R7) should a

vegetation-to-line contact (resulting in a sustained outage) occur. This situation amounts to regulatory double jeopardy. SCE believes that by any reasonable legal or regulatory measure, requiring a Transmission Owner to prove that a CCZ incursion did not occur is impractical and virtually impossible to enforce in a fair and impartial manner. Further, SCE believes that proposed R4 and corresponding M4 detracts from the purported goal of FAC-003-2 and should be removed.
Agree
Q16: SCE agrees in part with the establishment of R5, R6 and R7, however, we note that the opening of each requirement repeats a slightly altered version of the FAC-002-2 purpose statement. We find such repetitiveness unnecessary and note that as written, Requirements 5-7 presents a near identical compliance conundrum for Transmission Owners as Requirement 4. Again, Transmission Owners would be required to prove that they did not incur a sustained outage due to a vegetation caused flash-over or vegetation-to-line contact whether it be a grow-in, blow-in or fall-in. Although proving a sustained outage (for cause) did not occur will be difficult and unwieldy, it is not impossible. The simple difference between a Transmission Owner disproving the occurrence of a CCZ incursion and their disproving vegetation caused sustained outages, is that Transmission Owners do in fact keep records of â€œoutagesâ€☐. Because a Transmission Ownerâ€™s record keeping prowess is the only viable option for proving a vegetation caused outage did not occur, SCE respectfully suggests R5, R6 and R7 be revised to read: R5 - "Each Transmission Owner shall document Sustained Outages of applicable lines due to vegetation growing into a conductor operating within its Rating with the following exceptions:" R6 - "Each Transmission Owner shall document Sustained Outages of applicable lines due to vegetation blowing into a conductor operating within its Rating and located within an Active Transmission Line Right of Way with the following exceptions:" R7 - "Each Transmission Owner shall document Sustained Outages of applicable lines due to vegetation falling into a conductor operating within its Rating and located within an Active Transmission Line Right of Way with the following exceptions:" We also note that Footnote 6 is misplaced in the draft and should follow the word â€œOutagesâ€☐ in each of these requirements.
Agree
Q17: SCE agrees in part with the inclusion of R8, however, we believe R8 should be revised and renumbered to replace proposed R3. In SCEâ€™s view, the act of implementing a Transmission VM program encompasses both inspection and maintenance activities. SCE respectfully suggests that proposed R8 be revised to read: "Each Transmission Owner shall implement and follow its Vegetation Management Program to the extent allowed by existing easement and/or legal rights."
SCE notes that Section C (Compliance) is incomplete and that the associated levels of Non-Compliance listed in FAC-003-1 may be different from those proposed for FAC-003-2. SCE reserves the right to revise its initial comments and submit additional comments regarding the requirements, measures and compliance portions of FAC-003-2.
Group
SERC OC Standards Review Group
Jim Griffith
Southern Company
Disagree
The following comments are supplied by the SERC OC Standards Review Group (OCSRG): The definition of the Bulk Electric System generally does not include radial transmission lines directly serving load. The current standard covers all 200 kV and above transmission lines along with those lower voltage lines designated by the RRO while the BES includes all lines 100 kV and above. Use of the term Bulk Electric System will cause unnessesary confusion to the industry concerning applicability of this standard. Therefore, the SERC OCSRG recommends the continued use of the undefined term "electric transmission systems."
Disagree
The SERC OCSRG does not believe that the RC is the appropriate entity to identify sub-200 kV transmissions to be subject to this standard. Vegetation Management programs are longer than the normal operating horizons of RCs. We believe that the proper function to identify sub-200 kV transmission lines subject to this standard is the Planning Coordinator. This must be consistent with PRC-023, Requirement 3. We also recommend that a process be established for dispute resolution. NERC should develop a comprehensive approach to the determination of "critical" facilities rather than

pushing a piecemeal approach as evidenced by this standard and PRC-023, among others.
Agree
Agree
Disagree
While the SERC OCSRG agrees with this requirement in general, there may be areas (e.g., desert terrain) where an annual interval would be unnecessary and not cost effective.
Agree
Disagree
The Requirement as written is too prescriptive and is open to interpretation from an audit perspective with use of the term â€œimmediateâ€☐ communication and a partial list of activities. Due to limitations of communication capabilities in the field, "immediate" may not be practical. While the White Paper provides insight into what is accceptable communications to the Transmission Operator, the standard is less prescriptive in describing what is an acceptable communication path to the Transmission Operator. We recommend better descriptions in VSLs, measures and the RSAW as to what is acceptable. Many conditions or threats, requiring immediate removal, would not require communcation with the Transmission Operator, who is not an applicable entity for this standard. The SERC OCSRG recommends that R1.4 be deleted. Since this is a "zero tolerance" standard any Transmission Owner will remove any discovered threats to prevent outages. If R1.4 is not deleted, the SERC OCSRG believes that imminent threats should be a defined term. The definition should be as follows: â€œImminent Threat: A vegetation condition which, if not addressed, will place a transmission line at an immediate risk of a Sustained Outage.â€☐
Agree
Agree
Agree
Disagree
The SERC OCSRG recommends that R2 be deleted. Since this is a "zero tolerance" standard any Transmission Owner will remove any discovered threats to prevent outages. While we agree that the implementation of an imminent threat procedure may be a valid concept, visualization of the Critical Clearance Zone and determining an approaching encroachment is a practice in application of theoretical conductor locations in real time.
Agree
Developing minimum sparkover distances in this standard is a superior approach for the stated reason in question 12. In addition, referring to tables and values in another standard is problematic if the referenced standard is revised and the tables are re- numbered or deleted altogether. The SERC OOCSRG suggests that the tables based on the Gallet equations be removed from the standard and be kept in the technical white paper solely to assist in developing a common understanding of the threshhold for taking actions.
Agree
See comments in #12 above.
Agree
Disagree
The requirement, as written, compels the Transmission Operator to allocate precious resources to ensuring that a vegetation encroachment NEVER will occur on any transmission line, regardless of that line's true importance to maintaining electric transmission system reliability. All lines are not created equal; only those that are involved in IROLs should be held to a zero tolerance standard. R4, if retained, should begin with "Subject to its legal rights," and insert the word "vegetation" between

prevent and encroachment. Vegetation, which falls through the Critical Clearance Zone or falls to lodge within the Critical Clearance Zone, should not be included as violations of the Critical Clearance Zone. The concept of the Critical Clearance Zone is useful as a mental model to visualize required vegetation management work. While this is a good conceptual tool to drive consistent terminology and proper vegetation management practices, it remains theoretical in nature and impractical to measure on a span by span basis. The complexity of determining an encroachment into the Critical Clearance Zone is overly burdensome due to the need for survey accuracy measurements and engineering evaluations. In addition, this complexity leads to questions about the ability to audit this requirement. These complexities introduce reliability and audit issues when encroachments into this conceptual area are defined as violations. The SERC OCSRG believes the Sustained Outage, as defined by other measures in this standard, should be the non-compliance measure. We suggest that the Critical Clearance Zone concept be kept in the technical white paper and that all references to the Critical Clearance Zone be removed from the body of the standard. R5, R6, and R7 ensure that version 2 of the standard has reliability requirements equal to version 1; therefore R4 should be removed.
Disagree
R5, R6 and R7 should begin with "Subject to its legal rights,". The requirements, as written, compel the Transmission Operator to allocate precious resources to ensuring that a vegetation outage NEVER will occur on any transmission line, regardless of that line's true importance to maintaining electric transmission system reliability. All lines are not created equal; only those that are involved in IROLs should be held to a zero tolerance standard. R5, R6, and R7 ensure that version 2 of the standard has reliability requirements equal to version 1; therefore R4 should be removed.
Disagree
The SERC OCSRG suggests that the Requirement be reworded to read: â€œEach Transmission Owner shall implement its annual work plan for vegetation management within the Active Rights of Way." Any further verbiage is confusing, ambigious or unnecessary.
The SERC OCSRG recommends that the definition of "Active Rights of Way" be revised as follows: "A strip of land, designated by the Transmission Owner, that is occupied by active transmission facilities. This corridor does not include the inactive or unused part of the Right of Way set aside by the Transmission Owner for other facilities or uses." The SERC SOSRG recommends that this standard should exclude radial to load facilities and, for consistency, all 200 kV and above lines should not be included in the standard unless they meet the same requirements as sub 200 kV lines.
Individual
Jonathan Appelbaum
Long Island power Autority
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree

Agree
Agree
Agree
Agree
Agree
Disagree
The Standard is about preventing outages and having an effective program. An effective program should allow for the identification of a threat and the removal of the threat prior to a vegetation caused outage. I prefer alternative 2. If a vegetation caused outage should occur or if the Regional Entity determines a violation occurred based on a compliance investigation then the entity is in violation of this requirement.
Agree
Agree
1) Disagree with R1.1. The proposed standard is too lenient on the program documention required for an effective program. R1.1 should include the words " the program will document the program objectives, method of site evaluation, the definition of action thresholds, the control methodologies, and how the monitoring program is established". There is a wide gulf between listing IVM methodologies and a vegetation proram implementing A300. 2) CHANGE: Within Applicable Facilities listed in section 4.2 the phrase Transmission Line should be changed to Overhead Transmission Line. The NERC Glossary definition of transmission Line is: " A system of structures, wires, insulators and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances." The accompanying white paper states the standard is addressing the impact of vegetation growth on overhead transmission lines. The intent of this standard is the development and imlementation of a vegetation management program for overhead transmission lines only. By specifically stating "overhead transmission lines in Section 4.2 there will be no possibility of an occurrence of an auditor requesting a vegetation management program for underground lines.
Individual
Robert (Bob) B. Suedkamp
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM
Agree
Agree
Agree
My disagreement with R1
Agree
Disagree
It would seem also that the T.O. should be expected to react to circumstances that create the need for a more frequent inspection cycle such as conditions that cause widespread vegetation mortality such as drought and/or beetle infestations.
Disagree
I think that the Transmission Owner should be able to specify the effective period of the plan whether

it is one year or ten years. Arizona utilities are starting to think in terms of multi-year corridor management plans. A one year planning period could be specified as the minimum planning period.
Agree
The USFS would be expecting the Transmission Owner to be documenting the imminent threat procedures in an operating plan or corridor management plan that would be approved by the designated USFS decision maker. If such procedures are documented in the Transmission Owner's TVMP and are compatible with USFS resource management direction, then the imminent threat procedures could be incorporated in the agency-approved operating plan by reference. If the Transmission Owner disputes any restrictions that are placed by the USFS on the imminent threat procedures, the USFS has an administrative appeals process which the Transmission Owner can use, but those procedures can be time-consuming and probably would not be perceived by the Transmission Owner as being neutral for negotiation purposes. It might help if a third federal party like NERC could help resolve disputes between the Transmission Owner and the USFS on the imminent threat procedures. Although the USFS would object to unreasonable intrusion of NERC into normal USFS land management prerogatives, imminent threat procedures would seem to be a topic for which NERC should take a very strong position, especially with a standard that identifies minimum vegetation clearances as related to prevention of arcing potential, or in other words, vegetation that should be considered hazardous and in immediate need of treatment.
Agree
In my opinion, problems between the Transmission Owner and the USFS over the TVMP should be worked out before a TVMP is ever finalized. A dispute resolution process outside the control of either party would be very helpful and would probably facilitate quicker solutions than if the Transmission Owner and the USFS are left to work out problems on their own. If a TVMP is prepared in a vacuum, the problems may not come to light until some kind of outage actually occurs. It would be much better to flush any disagreements and deal with them before any outages actually occur.
Disagree
If it is possible for NERC to identify minimum clearance standards as related to arcing potential for hazardous vegetation, it would definitely help USFS field administrators to have some kind of hard and fast standards. If that kind of approach is not reasonable in light of the need to adjust standards for various load conditions and vegetation growth rates, then a prescribed formula for calculating minimum clearances would be the next best thing.
Disagree
Perhaps standard M8 could be expanded or clarified to require the Transmission Owner to describe how employees, especially field supervisors, are trained to implement the plan and to prove that the training was actually provided. Some problems have arisen in the USFS Southwestern Region because some Transmission Owners are not providing adequate supervision of field work.
Agree
Attachment 1 is very conservative. I think that the clearance distances shown on the attachment should be expanded to create, in effect, a standard that reflects maximum line loading and maximum line sag. I would also like to see some flexibility built into the process so that the Transmission Owner and the USFS could negotiate some consideration for vegetation growth rates. The end result would generate a standard that would give the Transmission Owner the security of knowing that vegetation would not grow into the potential arcing zone for some reasonable amount of time - some kind of entry cycle.
Agree
See comment for Question 11.
Don't know!
Agree
Disagree

The wording appears too strong. Who can predict the unforeseen circumstances that inevitably arise. If the standards require the reporting of encroachments, the ensuing report can help determine if the Transmission Owner did everything reasonable to avoid the problem. It seems like the standard should be written to require the Transmission Owner to do everything reasonable to avoid the problem. A judgement call would still be needed to evaluate the performance.
Disagree
I believe that the text for each element should be re-written with the general philosophy that the Transmission Owner shall do everything reasonable to prevent such problems in line with the comment for section 15. Problems should be reported and investigated and a judgement call should be made about whether the Transmission Owner did everything reasonable to avoid the problem.
Disagree
This standard needs to be broadened to include evaluation of the good faith efforts by the Transmission Owner to coordinate with the USFS on development of the work plan. A mechanism should be developed to allow the Transmission Owner to evaluate the good faith efforts of the USFS.
I'm having trouble getting comments to "stick" in this section of the form. I have a general concern with the opening paragraph of R1. The wording seems to encourage a Transmission Owner to develop a TVMP in a vacuum. The US Forest Service defintely wants input into the development of an annual work plan and USFS land use authorizations include a requirement for USFS approval of vegetation management plans. It seems much more reasonable to require the TVMP to reflect USFS or any other landowner resource management considerations. This tactic would require more "up front" work, but the end result is a plan which would reflect reasonable landowner input and where the disagreements could be settled ahead of time rather than being left for the night shift. I also believe that some kind of dispute resolution process is needed outside the control of either the Transmission Owner or the USFS. I think that NERC could fill that role very well.
Individual
Kris Manchur
Manitoba Hydro
Disagree
Manitoba Hydro disagrees with changing "electric transmission systems" to "Bulk Electric System" because BES applies to facilities 100kV and above which may not have an impact on system reliability.
Disagree
Manitoba Hydro disagrees that the RC is appropriately positioned to identify and designate any sub-200kV lines that should be subject to this standard. Lines below 200kV should include only those that are currently classified as Interconnection Reliability Operating Limit (IROL) lines which are already defined and listed for registered entities. As such R9 and R10 should be eleiminated from this standards along with the RC in the applicability section.
Agree
Agree
Agree
Agree
Agree with the seperation - but suggest that the time horizon of one year be removed as some changes may push the work beyond the curent planning year.
Agree
Suggest removing, "and may include actions such as a temporary reduction in line rating, switching lines out of service, or other actions", as this is outside the scope of a vegetation management program.
Disagree
Agree with the change in terminology - but would suggest that wording clarify that this is not only for situations where the utiity is unexpectedly prevented from implementing its annual plan - but also for

areas where it is unable to implement its clearance requirements due to property rights limitations.
Agree
Agree
Disagree
The imminent threat process trigger should be well defined, and the vague "approaching" terminology needs to be changed. Imminent threat implies and that an elevated risk of contact exists. That is not the case if the vegetation is merely approaching the CCZ. The objective of the overall Vegetation Management program is to prevent an encroachment. The imminent threat procedure should be triggered by discovery of an encroachment into the CCZ. Even when an actual encroachment into the CCZ occurs - while the odds of an outage event have increased - the likelihood of a contact is still minimal, as other environmental factors still need to be in place (ie. high temperature and/or high wind conditions). If this approach to an imminent threat process trigger, then the violation of this requirement implies a violation of R4, which prohibits the encroachment of the CCZ, and therefore either R2 or R4 could be removed, or they could be combined into one requirement.
Agree
Disagree
Manitoba Hydro has historically designed the ROW clearance requirements based on an operating limitation of not switching during extreame wind conditions, therefore, beyond a wind presure of 230 Pa, our design doesnot account for switching surge overvoltages. We do howerver, agree with the use of overvoltage factors as described above for wind conditions of less than 230 Pa.
Agree
Disagree
Manitoba Hydro asserts that the reliablity of the system is measured by outage, not by the possiblity of an outage, and therefore if the overall vegetation management system (plan-patrol-discover-mitigate) is effetive in preventing an outage, then the reliablity of the system has been maintained, and the intnent of the reliablity standard achieved. Therefore, we propose that the second bullet above is the prefered alternative, and that R2 and R4 be combined as the violation of R4 would then imply a violation of R2.
Agree
Agree with splitting the various events. We note that there is no specific requirement to actually report an outage. The Requirements say that we should Prevent Sustained Outages, but not actually report sustained outages should they occur. In version 1, R3 clearly stated that the Transmission Owner shall report.
Agree
Individual
Jianmei Chai
Consumers Energy Company
Disagree
Consumers Energy disagrees with changing the current "electric transmission systems" to "bulk electric system". This change will create confusion and can lead to a discrepency concerning lines operating below 200kV that may be included in the "bulk electric system" but are otherwise excluded from this standard.
Agree
Agree

Agree
Disagree
FERC required NERC in Order 693 to develop appropriate inspection cycles based on local factors. Potential annual tree growth varies considerably within the geography of the United States and FAC-003-1 recognized this factor and left it up to the utility to determine the most appropriate inspection cycle for their system. This was in lieu of having proper data readily available to determine inspection cycles for various areas that could be incorporated into the standard. FAC-003-2 greatly decreases the minimum separation distance between conductors and vegetation. Table 1 shows the minimum distance at sea level for a 345 kV line a 3.12 feet. This is considerably less than the potential annual growth rate of many tree species in many areas of the United States. Therefore, the annual inspection cycle would not be acceptable to identify tree growth that can violate the minimum distance before it occurs. Consumers Energy strongly believes that using the Gallet formula to determine the minimum clearance between conductors and vegetation will decrease the reliability of the system compared to the minimum clearance requirements in FAC-003-1.
Agree
Disagree
Consumers Energy believes that each Transmission Owner/Operator should have a Vegetation Imminent Threat Procedure. We disagree with this requirement because "vegetation imminent threat" is not defined in the standard. As interperted, the "vegetation imminent threat" is only what is needed to avoid violating the Gallet formula minimum distance which would allow vegetation approaching close to 3 feet of separation on 345 kV conductors. At this distance, removal of the tree cannot occur without removing the line from service per OSHA rules. Therefore, the tree can "cause" an outage but be acceptable under this standard. Consumers Energy believes that vegetation must be maintained so that extraordinary measures needed to remove the vegetation threat do not have to occur in order to complete the work. Thus, the minimum distance to "trigger" an imminent threat must be greater than the OSHA minimum working distance and therefore the Gallet formula does not provide the protection that FERC demands. During high load periods options a system operator may have to mitigate the vegetation threat may not be available; you may not be able to remove the line from service, derate the line, etc., so the operator must "hope" to get through the high load period without the vegetation causing a outage. Allowing vegetation to approach the Gallet formula distance is unacceptable and severely decreases the reliability of the system.
Agree
Agree
Agree
Disagree
Absolutely disagree! The Gallet formula distances do not provide adequate protection of the system. The "Critical Clearance Zone" concept is not workable in the field. Every foot of every span would have a different CCZ that cannot be measured in the field without survey type equipment and knowledge of current line loadings. The clearance requirement needs to be uniform along the span for field crews to effectively achieve compliance. It appears that the drafting team hopes to minimize violations of vegetation violating FAC-003-1 Clearance 2 distances by decreasing the clearance distance between the conductor and vegetation using the Gallet formula. If NERC believes that FAC-003-1 Clearance 2 distances are too conservative, then the Gallet formula distance needs to be increased by some multiplier (2 or3) to achieve adequate safeguard for growing vegetation. Most trees in the United States in the size range that could exist beneath conductors achieve height growth of 3 feet or more annually. A tree in May may have adequate clearance per the proposed CCZ and in July violate that clearance causing an outage. Therefore, if the CCZ is to remain as is then the transmission owner/operator must have a defined imminent threat distance considerably greater than the CCZ and must be great enough that field personnel can safely remove the threat without de-energizing or de-rating the line.

Disagree
The Gallet distances severely lessen the reliability of the tranmission system since there is not a define imminent threat distance and the Clearance 1 distances have been removed from this draft. The IEEE 516 distances provided a safety margin to allow for vegetation to grow and not be a reliability risk. A transmission owner/operator of a moderate size could not effectively inspect often enough during the growing season to protect lines from outages when trees are permitted to approach the Gallet formula distance and not be a violation. Such close distances would permit utility management to severely cut vegetation management budgets and allow trees to grow for 1-2 years beyond their scheduled maintenance cycle and not be in violation. But, 2-3 years after the budget cut, the field operation would be faced with an insurmountable amount of trees needing addressed and limited timeframes to complete the work. This is basically how the blackout occurred and this standard decreases the requirements to allow this to happen again.
Agree
Agree
Disagree
The CCZ does not provide adequate clearance and the imminent threat procedure if successfully implemented only works IF YOU KNOW ABOUT THE VEGETATION THAT THREATENS THE CCZ which cannot be ensured with yearly inspections. Consumers Energy believes that the Clearance 2 distances in FAC-003-1 provide more reliability than the CCZ proposed in this draft or any of the alternatives disussed above.
Disagree
R5, R6 and R7 should be rewritten as a single requirment for vegetation within the "Active Transmission Line Right of Way" and the exceptions listed. Additionally, a requirement for hazardous trees outside of the "Active Transmission Line Right of Way" should be incorporated into this draft and similar exceptions listed for natural disasters, third-party, and animal causes.
Agree
The annaul work plan should be designed to avoid vegetation growing into a violation of the CCZ or whatever minimum distance is acceptable. Since the plan can change throughout the year, it needs to be flexible, it should be stated that the plan at a minimum must provide adequate funding to prevent vegetation growth from violating the minimum clearance distance. The flexibility of change should be limited to changing to address emergent needs for vegetation management and not reductions in funding that delay maintenance in the hopes that additional funding at some future point in time will be adequate to remove the backlog of vegetation maintenance. The Purpose of the standard should be revised to state "(To maintain minimum clearance sufficient to avoid any vegetation-related Sustained Outages for all applicable conditions) for all Transmission Lines covered by this Standard" as provided by FERC in Order 693, Paragraph 731. The purpose as stated in FAC-003-2 waters down the intent of FERC to "improve the reliability" and is only applicable to "outages that could lead to cascading".
Individual
Dawn Travalini
National Grid
Disagree
Use of the term Bulk Electric System will cause unnessesary confusion to the industry concerning applicability of this Standard.
Disagree
No opinion.
Agree
Defining "Active Transmission Line Right-of-Way" solves the Right-of-Way definition problem within the SAR.
Agree

These revisions and separation make it easier to match requirements and measures.
Disagree
R1.2, M1.2 and M1.3 in the Standard all refer to calendar year. National Grid objects to inspections being based on a calendar year. Transmission Owners should be able to define their own "year". (See Question No. 18.)
Agree
Agree
Disagree
National Grid agrees replacing mitigation plan with corrective action process. However, National Grid questions the use of "interim" for a corrective action process in R1.5, and suggests striking "interim".
Disagree
National Grid takes exception to the term "fill-in-the-blank". National Grid disagrees with the elimination of Clearance 1. The Clearance 1 requirement in FAC-003-1 was meant to allow a Transmission Owner to establish clearances to be achieved at the time of vegetation management work, and be sensitive to local and regional conditions. National Grid believes that Clearance 1 is needed for public education and safety reasons. Clearance 1 standards allow utilities to specify a cyclic programmatic approach, and gives the utility leverage with local and state regulators and the public to achieve significantly larger than minimal clearances.
Disagree
National Grid takes exception to the term "fill-in-the-blank". National Grid would like Personnel Qualifications to remain in Standard FAC-003-2.
Agree
Agree
Disagree
No opinion.
Agree
Agree
National Grid agrees that there should be no encroachments into the CCZ. However, encroachments in the CCZ should NOT be considered a violation. Violations should only be for sustained transmission outages.
Agree
National Grid agrees with the proposed change, however, Standard FAC-003-2 does not provide outage reporting requirements in R5, R6, R7, or anywhere else in the Standard.
Agree

National Grid has the following comments: 1. Transmission Owners should be able to define their own inspection "year" and not be locked into a calendar year time frame. National Grid performs inspections at least once per vegetation growth year. Under our Vegetation Management Program, growth years are not skipped, and our inspections occur prior to new growth every year. For example, a transmission right-of-way may be inspected in December 2008 and the right-of-way is next inspected in February 2010. Under this scenario, the inspections occurred 14 months apart, but only one growth year occurred between inspections, and each inspection is ahead of the next year's growth. Transmission Owners need this flexibility to deal with regional growth rate differences and climate. 2. Section C., Compliance, of Draft Standard FAC-003-2 states "To be added". Issuance of Draft Standard FAC-003-2 should have been delayed for comments until all sections were complete. This section is likely to include the outage reporting and self-certification requirements. Transmission Owners need the opportunity to comment on these items. 3. With the elimination of Clearance 1 and reducing Clearance 2 clearances, there is concern that FERC will view Standard FAC-003-2 as a watered down version of Standard FAC-003-1.
Individual
Stephen Tankersley
Pacific Gas & Electric Co.
Agree
Agree
Agree
Agree
Agree
This requirement is appropriate to ensure adequate inspection frequencies, however, a clear definition of "inspection" should be contained in either the standard or white paper.
Agree
Agree
PG&E agrees an imminent threat procedure is a critical component of the standard and should be contained in the TVMP. See additional comments for Q11.
Agree
Agree
Agree
Disagree
PG&E agrees the Gallet equation is superior to IEEE 516 and the imminent threat procedure is a critical component of the standard but disagrees that initiation of the procedure be based on such ambigous language as "approaching the CCZ". Approaching could be any and all vegetation that is live and growing and CCZ is a theoritical calculation not a real time event. As written, the standard would require the TO to initiate an emergency action when such action may not be warrented or necessary to prevent an outage. PG&E recommends using a clearly defined and measureable threshold to determine when the imminent threat procedure must be initated. A reasonable threshold would be 3 times the Gallet clearance distances referred to in Table 1 or when vegetation is threatening to fall into or otherwise impact a line.
Agree
Agree

Agree
Disagree
PG&E believes a "minimum clearance distance" or "do not encroach zone" is a critical element of this standard and necessary to achieve the stated purpose of preventing vegetation caused outages. Preventing vegetation encroachments will prevent outages. However, PG&E disagrees with using the CCZ as a minimum clearance requirement because it is ambigous and subject to wide variations and intrepretation. CCZ is a good concept to aid in understanding movement of conductors but is a theoretical calculation and would be very difficult if not impossible to enforce. PG&E suggests using a clearly defined distance such as Gallet equation plus a safety margin to assure there is no chance of spark over. Two times Gallet would be a reasonable clearance requirement to assure a spark over does not occur and eliminate the ambiguity of the CCZ as the "do not encroach zone".
Agree
M5, M6 and M7 do not explcity exclude the exceptions in R5, R6 and R7 and should do so.
Agree
PG&E agrees with the requirement to implement the annual work plan, but recommends removing the language "within the extent of its easement and/or legal rights".
1) The standard should be clear that it applies to all Federal and Non-Federal land. PG&E further recommends additional language specifically dealing with Federal land such as application of ANSI A300. 2) The standard should specify applicability inside substations.
Group
Western Utility Arborists
Mike Neal
Western Utility Arborists
Agree
Yes, we agree.
Agree
Yes, we agree.
Agree
Yes, we agree, subject to the qualification about â€œactiveâ€☐ rights-of-way under Comment #16. Under R1.1, it says â€œSpecify the methodologies that the Transmission Owner uses to control vegetation.â€☐ The single word â€œmethodologiesâ€☐ does not adequately replace â€œobjectives, practices, approved procedures, and work specifications.â€☐ The Western Utilities recommends keeping the original wording. We would also like to point out that the original intent of the standard was to ensure that utilities had a complete vegetation management program. The new standard is evolving towards an outage control program, and no longer encourages programs or behaviours that would ensure the causes of outages are prevented long before they become a problem. The standard now redirects efforts to avoiding outages instead of managing vegetation.
Although itâ€™s important to have these two separate aspects â€“ documentation and implementation â€“ separating them spatially in the document itself makes the standard longer than necessary and creates redundancy. It seems obvious that if you prepare elements of the TVMP, they also need to be implemented. The document would be easier to follow if the two elements were kept together.
Clarification is required on exactly what an inspection is, which should perhaps be outlined in the white paper. There are areas where inspections are not necessary at all, such as lines over a parking lot, or in a remote desert area. The Western Utilities need some assurance that this inspection will not constitute a dedicated, comprehensive vegetation management inspection. Inspections are currently often part of a routine line patrol, where the lineman looks for vegetation concerns in addition to undertaking maintenance work. Therefore, the Transmission Owner needs the ability within their TVMP to define what an inspection is in the context of their utility operations.
The document would benefit from keeping the two requirements together, since they relate to the same topic. Under the new wording in R1, the TVMP no longer has a requirement to include

objectives. However, there is a phrase in R1.3 to â€œsupport the objectivesâ€¦and methodologiesâ€¦outlined in theâ€¦program.â€☐ To be consistent with R1.3, the Western Utilities recommends that R1.1 be reworded to specify the methodologies and objectives that the Transmission Owner uses to control vegetation.
Agree
We agree with 1.4, with the following qualification: Any standard that is developed should not contain advisory-type languageâ€”it should be declarative in tone. For example, in R1.4, the ending clause that begins â€œâ€¦and may include actionsâ€¦â€☐ should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program.
Agree
Yes, we agree.
Disagree
The Western Utilities do not agree with the removal of Clearance 1. We recommend adding it back to the document, but reworded and moved to include it as a measurement (M), rather than a requirement (R) under the new standard. Many utilities feel that Clearance 1 provides justification and leverage for operational clearances when dealing with organizations such as municipalities. Without Clearance 1, utilities could be mandated in specific situations to clear so that the vegetation is just beyond the CCZ at all times. This could result in pruning at six month intervals, which is not feasible or cost-effective.
Agree
The Western Utilities are in agreement with the elimination of this requirement. However, we feel strongly there must be appropriate knowledge to do the work, and that Transmission Owners must at least have internal standards related to personnel qualifications.
The Western Utilities feel that changing to the Gallet equation will not have a large impact on its vegetation management operations, so we have no concerns. We agree with R2, but feel that this clause makes R4 redundant, as per our discussion under Comment # 15 below. We recommend the removal of R4 entirely from the standard.
Agree
The Western Utilities feel that changing this will not have a large impact on its vegetation management operations, so we have no concerns.
Agree
The Western Utilities feel that changing this will not have a large impact on its vegetation management operations, so we have no concerns.
The Western Utilities understands that itâ€™s possible to have a schedule and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the schedule is kept together with the requirement to implement it.
The new requirement in R4 stipulates that the Transmission Owner is in violation if an encroachment of the CCZ occurs at any time. However, the CCZ changes with each foot of the transmission line from the insulator to the mid-span, depending on loading, actual operating temperature, wind loading, ice loading, maximum design rating, maximum operating load, and so on. Further, measure M4 requires that the Transmission Owner has evidence demonstrating there were no vegetation encroachments into the CCZ. To provide evidence demonstrating there were no vegetation encroachments into the CCZ would be an extremely onerous task and an expensive requirement for the Utilities. The Western Utilities strongly supports the alternative to R4 as recommended in the Comment Form (#15), which is to require immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the CCZ, thereby proactively preventing an outage. This means a violation would occur only if the imminent threat process is not successfully implemented. This alternative is essentially the same as R2. Therefore, the Western Utilities recommend removing R4 from the standard entirely.
The Western Utilities strongly recommend that the requirement under R7 be changed from â€œshall prevent sustained outagesâ€☐ to â€œshall minimize sustained outages due to vegetation falling into a conductor.â€☐ We note that the word â€œminimizeâ€☐ was present in earlier drafts of the document. We are concerned about the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW. It is operationally

almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. This could lead to an incident where utilities are charged unreasonably â€“ for example, for an outage from a tree that was one foot within the active ROW line. We should not be held liable when reasonable due diligence is practiced. Further, it is not economically feasible for utilities to survey every ROW in the U.S. and Canada to determine precise clearance zones.
The Western Utilities understands that itâ€™s possible to have an annual plan and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the plan is kept together with the requirement to implement it.
Any standard that is developed should not contain advisory-type languageâ€”it should be declarative in tone. For example, in R1.4, the ending clause that begins â€œâ€¦and may include actionsâ€¦â€□ should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program. ADDITIONAL COMMENTS We have prepared, and will submit via email, additional comments regarding our online submission. If the ability to submit them electronically is not available on this website, we will send the complete document via email to Harry Tom and would ask that it be reviewed and considered by the drafting team.
Group
Florida Power & Light
John Tamsberg
Transmission Operations
Disagree
The Purpose Statement of any regulation or standard should be completely consistent with the body of regulation or standard. Here the use of Bulk Electric System (which is defined as 100 kV and above) is inconsistent with the language of the Standard that states this Standard applies to 200 kV and above. One of the primary purposes of re-drafting a Reliability Standard is to clear up any previous confusion -- here the Purpose Statement instead of adding to clarity, adds an uncessary element of confusion. Thus, the Purpose Statement should be re-written to state 200 Kv and above.
Agree
Agree
Agree
Agree
Agree
Disagree
The definition of Imminent Threat procedure should be included in the Standard. As FERC has stated with regard to the definition of sabotage, the industry should come up with a standard definition and it should not vary from company-to-company. FPL further disagrees with defining Imminent Threat only in a white paper as proposed by some. The Standard should not refer to other reference documents, especially when it is to add clarity and should define the Imminent Threat procedure as well as its requirements within the body of the Standard.
Agree
FPL neither agrees or disagrees with this removal but provides the following comment. FPL's experience regarding Clearance 1 is that it was an effective way of demonstrating a measurable requirement for compliance when dealing with public entities. The use of a corrective action process to mitigate instances where this clearance was not met before violations ocurred is also very effective in promoting reliability and safety in the Standard.
Agree
Disagree

FPL agrees that the Gallet equation is a better method to determine a Critical Clearance Zone. However, FPL does not agree with the application of the zone for several reasons outlined below. â€¢ There are many environmental and engineering variables and assumptions included in the calculation of the Critical Clearance Zone. â€¢ These assumptions are not clearly defined in the standard. â€¢ Unless there is a significant intrusion into the Critical Clearance Zone, an engineer and surveyor would be necessary at all times to determine a violation. â€¢ The success of this standard lies with a standard the field personnel can implement. When making actual trimming or removal decisions, the field personnel are not adequately skilled to do much more than make a rough guess at the Critical Clearance Zone. This standard must establish measurable and auditable parameters for field operations. â€¢ In Requirement R2, determination of when to activate the Imminent Threat Procedure becomes unclear due to the difficulty in determining when the Critical Clearance Zone is encroached. â€¢ As written, off ROW trees falling through the Critical Clearance Zone become a violation of Requirement R4. Unless an outage occurred, how would the utility determine that a violation occurred? In FAC 003-1 an outage of this nature is defined as Category 3 and is not a violation. Since fall-in tree interruptions have never been contributors to cascading events or blackouts they should not be a violation of a NERC standard. Consequently, as written, it is highly questionable whether this Standard is sufficiently specific and clear to be enforceable. The many questions and levels of confusion introduced with the application of the Critical Clearance Zone concept suggests that neither the industry nor NERC will ever know if compliance is met. Such a high level of ambiguity requires that the Critical Clearance Zone concept be revisited and most likely replaced with a measure that is workable for both the industry and NERC. To further this effort, FPL has outlined some alternative suggestions described in the answer to question 18.
Agree
Agree
Agree
Disagree
NERC standards require the Transmission Owner certify annually that they are in compliance to the standard for the entire year. Since there is no way that a Transmission Owner could monitor every span of line every minute of every day, Requirement R4 cannot be certified. A Transmission owner can only certify that at the time inspected the system met the specification in the standard and that implementation of its Transmission Vegetation Management Plan maintains these specifications. As stated earlier, the Critical Clearance Zone is difficult to accurately identify in the field and without an outage it would be difficult for an auditing body to find and validate. Requirements R4-R7 are reactive in nature. They are violations after the event has occurred or when the tree - wire relationships are so close that emergency action is the only recourse for the Transmission Owner. The standard needs to drive the Transmission Owner to identify and remove trees threatening the system in a proactive fashion. A Transmission Owner should never be in violation for timely action to remove a threat to the system.
Disagree
As currently written, Requirements R5, R6 and R7 demand perfection. The only acceptable number for all 150K miles of affected transmission line in the US is 0. The standard should be achievable and enable proactively addressing potential threats to facilities from vegetation. Even using a Six Sigma level of quality and control, processes can achieve a level of 3.4 defects per million opportunities for defect. Each tree on the ROW represents one of those opportunities. FPL has outlined an alternative proposal in response to Question 18.
Disagree
The standard goes to great length to specify the Active Transmission Right-of-Way but omits its reference in requirement R8. The inclusion of this term in Requirement R8 adds consistency to the application of the standard. FPL suggests the following change: "Each Transmission Owner shall implement its annual work plan for vegetation management to accomplish the purpose of this standard within the extent of its easement ans/or legal rights in the Active Transmission Line Right-of-Way."

FPL believes the Vegetation Management standard should concentrate on grow-in tree issues that contribute to cascading or blackout events as stated in the purpose statement. Fall-in trees from either on or off ROW do not in-and-of themselves cause cascading or blackout events. Transmission systems are appropriately designed to handle incidental outages under N-1 conditions which are the case in fall-in type outages. Requirements relating to fall-in and blow-in outages (R6 and R7), which deal with incidents resulting from force majeure or acts of God, should be removed to allow resources to be allocated to addressing events related to grow in interruptions. Because of an utter lack of control or such situations, no Standard or regulation places a duty on one to control force majeure or acts of God, yet that is precisely what R6 and R7 intend to do. If R6 and R7 stay in its current form, this will be yet another reason why this Standard as written will be unenforceable. FPL recommends the following approach. The entire US Transmission system was built under the National Electric Safety Code (C2). That code uses the Reference Component as the initial building block for establishing the lowest height of a conductor for all operating and designed environmental conditions. Over most open land this distance is 14 feet. FPL recommends creating a new requirement to clearly define a trimming standard. New Requirement At time of trimming, trees under conductors should be trimmed or removed so that the average growth would remain below the Reference Component of Rule 232 in the National Electric Safety Code C2. The wire zone should extend to the blowout distance calculated at 39 miles per hour (Fresh Gale) not to exceed the Active Transmission Right-of-Way. Where the Transmission Owner can not achieve that clearance, they shall have a permanent (ex. raised conductor) or interim (ex. short trim cycles) corrective action plan in place to prevent tree wire conflicts. Permanent corrective action plans should reside in the Transmission Owner's vegetation program record keeping system (database) for application when that line is maintained or inspected. Trees to the side of the ROW should be maintained at the edge of the Active Transmission Right-of-Way. The value in this approach is in its application by arborists and tree trimmers in field conditions. This approach is clear and measurable without a surveyor or an engineer present. The line design calculations were made to the NESC Standard at the time the line was built and incorporate all potential conductor locations within its flight path. As it stands now if there is a violation to R4, R5, R6, or R7 it is already too late. The standard should seek to identify and correct poor performers before they create a reliability threat to the system. In the field, a poor performer has many trees close to the line and will have to do many emergency cuts. It will also have more momentary interruptions before it has a single Sustained interruption. Sustained Interruptions have a history of contributing to cascading and blackout events. The standard should measure performance and penalize poor performance. The changes below reflect performance measurements with a graduated penalty applied to the metric. Change R2 to read Each Transmission Owner shall implement its Imminent Threat procedure when the Transmission Owner has knowledge, obtained through normal operating practices or notification from others, that the tree / conductor distance is less than the minimum clearance distance as specified in Table 2 of ANSI Z133.1-2006 (the minimum approach distance for qualified line-clearance arborists or qualified line-clearance trainees). Transmission Owners are to document and report activation of the Imminent Threat Procedure for violation of Table 2. Activation of the Imminent Threat Procedure for other causes shall not be reportable. The Violation Severity level should read: Activation of the Imminent Threat Procedure for encroachment of Table 2 of ANSI Z133.1-2006 (the minimum approach distance for qualified line-clearance arborists or qualified line-clearance trainees) has the following severity level: Lower â€“ Greater than 5 per 1000 miles of line and less than 7 Moderate â€“ Greater than 7 per 1000 miles of line and less than 9 High - Greater than 9 per 1000 miles of line and less than 13 Severe - Greater than 13 per 1000 miles of line Trees inside of Table 2 can only safely be trimmed under a clearance from the system operator, using special techniques under a line right of way from the system operator, or by a lineman with a live line permit from the system operator. No utility wants to let a tree get so close to energized lines such that it has to take the line out of service for a tree trim. It should be noted that Table 2 represents an established industry standard which is normally found placarded on the side of every tree trimming easement truck and bucket truck. It is minimum knowledge for every qualified line-clearance tree person under OSHA regulations. This is a distance that field personnel understand. New R5 to read: Each Transmission Owner shall minimize Momentary Outages of applicable lines due to vegetation growing into a conductor with the following exceptions: â€¢ Sustained Outages of applicable lines that result from natural disasters. â€¢ Sustained Outages of applicable lines that result from human or animal Activity. The Violation Severity level should read: Lower â€“ Having Momentary Outages Greater than 3 per 1000 miles of line and less than 6 Moderate â€“ Having Momentary Outages Greater than 6 per 1000 miles of line and less than 8 High - Having Momentary

Outages Greater than 8 per 1000 miles of line and less than 12 Severe - Having Momentary Outages Greater than 12 per 1000 miles of line New R6 to read: Each Transmission Owner shall minimize Sustained Outages of applicable lines due to vegetation growing into a conductor with the following exceptions: â€¢ Sustained Outages of applicable lines that result from natural disasters. â€¢ Sustained Outages of applicable lines that result from human or animal Activity. The Violation Severity level should read: Lower â€“ Moderate â€“ High - Having Sustained Outages Greater than 1 per 1000 miles of line Severe - Having Sustained Outages of 2 or greater per 1000 miles of line These VSL's listed above constitute a strawman for discussion. The drafting team could request historical performance data from Transmission Owners to statistically evaluate where the VSL should be set. As time progresses, future performance data could be re-evaluated to reset the limits. These changes bring the standard back in line with measurable and auditable requirements which provide practical field measurements to the personnel who can make the difference. These parameters provide measurements to indicate the tree health of the system. On a separate note, FPL believes that clarifying information captured in footnotes within the standard should specifically be referenced and made part of the standard. These notes add clarity and better define the standard requirements.
Individual
Rich Salgo
NV Energy (fka Sierra Pacific / Nevada Power Co.)
Agree
Agree
Agree
Yes, we agree, subject to the qualification about â€œactiveâ€☐ rights-of-way under Comment #16. We would also like to point out that the original intent of the standard was to ensure that utilities had a complete vegetation management program. The new standard is evolving towards an outage control program, and no longer encourages programs or behaviours that would ensure the causes of outages are prevented long before they become a problem. Instead, it redirects efforts to avoiding outages instead of managing vegetation. If this is now the preferred approach, the term TVMP is no longer valid and should perhaps be changed to the Transmission Vegetation Outage Prevention Program. Under R1.1, it says â€œSpecify the methodologies that the Transmission Owner uses to control vegetation.â€☐ The single word â€œmethodologiesâ€☐ does not adequately replace â€œobjectives, practices, approved procedures, and work specifications.â€☐ We recommend that the SDT retain the original wording.
Disagree
Although itâ€™s important to have these two separate aspects â€“ documentation and implementation â€“ separating them spatially in the document itself makes the standard longer than necessary and creates redundancy. It seems obvious that if you prepare elements of the TVMP, they also need to be implemented. The document would be easier to follow if the two elements were kept together.
Disagree
Clarification is required on exactly what an inspection is, which should perhaps be outlined in the white paper. There are areas where inspections are not necessary at all, such as lines over a parking lot, or in a remote desert area. We need some assurance that this inspection will not constitute a dedicated, comprehensive vegetation management inspection. Inspections are currently often part of a routine line patrol, where the lineman looks for vegetation concerns in addition to undertaking maintenance work. Therefore, the Transmission Owner needs the ability within their TVMP to define what an inspection is in the context of their utility operations.
Disagree
The document would benefit from keeping the two requirements together, since they relate to the same topic. Under the new wording in R1, the TVMP no longer has a requirement to include objectives. However, there is a phrase in R1.3 to â€œsupport the objectivesâ€¦and methodologiesâ€¦outlined in theâ€¦program.â€☐ To be consistent with R1.3, we recommend that R1.1 be reworded to specify the methodologies and objectives that the Transmission Owner uses to control vegetation.

Agree
We agree with 1.4, with the following qualification: Any standard that is developed should not contain advisory-type languageâ€”it should be declarative in tone. For example, in R1.4, the ending clause that begins â€œâ€¦and may include actionsâ€¦â€□ should be removed because it is advisory in nature. The suggested actions are not even applicable under the scope of a vegetation management program.
Agree
Disagree
We do not agree with the removal of Clearance 1. We recommend adding it back to the document, but reworded and moved to include it as a measurement (M), rather than a requirement (R) under the new standard. Many utilities feel that Clearance 1 provides justification and leverage for operational clearances when dealing with organizations such as municipalities. Without Clearance 1, utilities could be mandated in specific situations to clear so that the vegetation is just beyond the CCZ at all times. This could result in pruning at six month intervals, which is not feasible or cost-effective.
Agree
We are in agreement with the elimination of this requirement, but not without some qualifications. We feel strongly there must be appropriate knowledge to do the work, and that Transmission Owners must at least have internal standards related to personnel qualifications. It is unfortunate that this important requirement for an effective vegetation management program has been removed due to concerns with the auditing program.
Agree
We feel that changing to the Gallet equation will not have a large impact on its vegetation management operations, so we have no concerns. We agree with R2, but feel that this clause makes R4 redundant, as per our discussion under Comment # 15 below. We recommend the removal of R4 entirely from the standard.
Agree
We feel that changing this will not have a large impact on its vegetation management operations, so we have no concerns.
Agree
We feel that changing this will not have a large impact on its vegetation management operations, so we have no concerns.
Disagree
We understand that it is possible to have a schedule and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the schedule is kept together with the requirement to implement it.
Disagree
The new requirement in R4 stipulates that the Transmission Owner is in violation if an encroachment of the CCZ occurs at any time. However, the CCZ changes with each foot of the transmission line from the insulator to the mid-span, depending on loading, actual operating temperature, wind loading, ice loading, maximum design rating, maximum operating load, and so on. Further, Measure M4 requires that the Transmission Owner has evidence demonstrating there were no vegetation encroachments into the CCZ. These requirements may result in having to LIDAR the lines annually, to prove that trees have not encroached upon the CCZ. This would be an extremely onerous and expensive requirement for utilities. NV Energy strongly supports the alternative to R4 as recommended in the Comment Form (#15), which is to require immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the CCZ, thereby proactively preventing an outage. This means a violation would occur only if the imminent threat process is not successfully implemented. This alternative is essentially the same as R2. Therefore, we recommend removing R4 from the standard entirely.
Disagree
We strongly recommend that the requirement under R7 be changed from â€œshall prevent sustained outagesâ€□ to â€œshall minimize sustained outages due to vegetation falling into a conductor.â€□ We note that the word â€œminimizeâ€□ was present in earlier drafts of the document. We are

concerned about the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. This could lead to an incident where utilities are charged unreasonably â€“ for example, for an outage from a tree that was one foot within the active ROW line. We should not be held liable when reasonable due diligence is practiced. Further, it is not economically feasible for utilities to survey every ROW in the U.S. and Canada to determine and document precise clearance zones. Such costly effort would not produce any benefit to the reliabililty of the bulk electric system.
Disagree
We understand that it is possible to have an annual plan and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the plan is kept together with the requirement to implement it.
These comments were made with collaboration with other Western Utilities in a conference on this topic held in Denver. Any standard that is developed should not contain advisory-type languageâ€”it should be declarative in tone. For example, in R1.4, the ending clause that begins â€œâ€¦and may include actionsâ€¦â€☐ should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program. NV Energy and the other Western Utilities support the development of this white paper as a way to help ensure consistent interpretation of the standard. Perhaps the lack of such a paper in the first version of the standard contributed to the varying interpretations by the auditors. The utilities understand however that this document is not a legal document and is not binding.
Individual
Patricia vanMidde
San Diego Gas & Electric
Agree
Agree
Agree
Yes, we agree, subject to the qualification about "active" rights of way under comment 16. Under R1.1 it says "Specify the methodologies that the Transmission Owner uses to control vegetation." The single word "methodologiees" does not adequately replace "objectives, practices, approved procedures, and work specifications." We recommend keeping the original wording.
Disagree
The document would be easier to follow if kept together. Separation of the recommendations and implementation will make this a redundant process, because both will say the same thing.
Agree
The term "inspection" needs to be better defined, as well as the term "calendar year."
Agree
To be consistent with R1.3, we recommend that R1.1 be reworded to specify the methodologies and objectives that the Transmission Owner uses to control vegetation.
Agree
We recommend that any advisory language be removed, and replaced with a declaration to the utilities.
Agree
Disagree
We do not agree with the removal of Clearance 1. We recommend that it be added back into the document, but reworded and moved so it be included as a measurement, rather than a requirement. Without Clearance 1, utilities could be mandated in specific situations to clear so that vegetation is just beyond the Critical Clearance Zone at all times, which is not feasible or cost effective.
Disagree
We feel there must be appropriate knowledge to do the work, and that Transmission Owners must at

least have internal standards related to personnel qualifications.
Disagree
We do not agree with replacing Clearance Zone 2 with the Critical Clearance Zone. We recommend the removal of R4 entirely from the standard.
Agree
Agree
Disagree
The information should not be separated. It will be much easier to follow if the requirement to have the schedule is kept together with the requirement to implement it.
Disagree
The new requirement in R4 stipulates that the Transmission Owner is in violation if an encroachment of the Critical Clearance Zone (CCZ) occurs at any time. However, the CCZ changes with each foot of the transmission line from the insulator to the mid-span, depending on loading, actual operating temperature, wind loading, ice loading, maximum design rating, maximum operating load, and so on. Further, Measure M4 requires that the Transmission Owner have evidence demonstrating there were no vegetation encroachments into the CCZ. These requirements may result in having to LIDAR the lines annually to prove that trees have not encroached upon the CCZ. This would be an extremely oerous and expensive requirement for utilities. We strongly support the alternative to R4 as recommended in the Comment Form, which is wto require immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the CCZ, thereby proactively preventing an outage. This means a violation would occur only if the imminent threat process is not successfully implemented. This alternative is essentially the same as R2. Therefore, we recommend removing R4 from the standard entirely.
Disagree
We recommend that the requirement under R7 be changed from "shall prevent sustained outages" to "shall minimize sustained outages due to vegetation falling into a conductor." The word minimize was present in earlier drafts of the document. We are concerned with the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission Right of Way. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. This could lead to an incident where utilities are charged unreasonably.
Disagree
We feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the plan is kept together with the requirement to implement the plan.
We feel that any advisory-type language should be removed from the standard and replaced with wording that is in a declarative tone. We support the development of the white paper as a way to help ensure consistent interpretation of the standard.
Individual
David Kiguel
Hydro One Networks Inc.
Agree
Agree
Disagree
We agree in changing the text as proposed only if R1 is expanded as suggested below. The standard as written is primarily, if not exclusively focussed on outage prevention through one means, to keep vegetation out of the Critical Clearance Zone. The burden to accomplish this is placed on the Transmission Owner/Operator as it should be. The first section highlights that a program is required, but does not provide a requirement above this simplistic view, and from our perspective the Measures do not introduce any further rigour. This simplistic approach, in our opinion, does not adequately

address the reliability risks associated with the various methodologies of managing vegetation. The White Paper notes removal is superior to pruning in ensuring tree conflicts do not occur. The White Paper includes elements of vegetation management risks, but the revised standard for the most part excludes this issue. One could argue that the audits and fines will manage reliability risks, but we are not convinced that this will do so in a consistent and adequate manner. There are numerous clearance risk factors associated with managing vegetation on rights of way. Some of these are: accurate measurement of conductor sag, accurate measurement of vegetation, vegetation growth rate, conductor sway, tree movement. If one looks at Table 1, the Clearance Distances are to the nearest cm or 1/100 of a foot. This makes one wonder, how realistic are the expectations laid out in the standard? To manage the risks around the Critical Clearance Zone the Standard requires each Transmission Owner to work with these precise numbers and build in a margin of safety to manage the situation. Will each Transmission Owner use identical criteria to trigger work? This doubtful, so this leads one to believe that the standard has not been designed to produce consistent results, which in our opinion is the case. So one has varied field conditions that are difficult to nail down, precise clearance requirements to the nearest 1/100â€™ and the likelihood of inconsistent margins of safety. We realize that the audit process will help to assess these situations, but it may not be enough to achieve a somewhat uniform risk profile across the transmission systems. Other standards that we are familiar with include a margin of safety such as added clearance above the absolute minimum recognizing that it may not be practical to work to such precise measures. Examples of standards that use this approach to ensure consistent and reliable results include OHSA and the Canadian Standards Association. We are not advocating that this standard follows an identical approach, but do want to highlight that the standard may fall short in the area of managing vegetation management risks which in turn have a direct impact on reliability. Considering the above, it is suggested that the aspect of managing vegetation reliability risks be added to the White Paper to allow Transmisison Owners to develop somewhat consitent criteria. Further on the topic of managing risk. We believe that reliability risks are directly related to the amount of incompatible vegetation on a right of way that is approaching the Critical Clearance Zone. Incompatible vegetation would be vegetation that has the potential to grow into the Critical Clearance Zone at full growth. We suggest that risks could be reduced significantly by including direction in the standard concerning the management of incompatible vegetation. This would drive a greater degree of consistency among Transmission Owners and would reduce the amount of vegetation on rights of way that have the potential to cause flashover. In addition, this would reinforce the reliability risks associated with vegetation, not just from a clearance perspective but also from a volume perspective, and would provide a more comprehensive view for the public and interest groups. In order to respond to what we consider a shortcoming of the proposed standard, our suggestion would be to expand R1.1 similar to the following: Specify the methodologies that the Transmission Owner uses to control vegetation and demonstrate that the removal of non-compatible vegetation is a focus within the plan. It is recognized that reliability risks increase appreciably with an increase in incompatible vegetation on an active right of way, and the Transmission Owner is required to remove incompatible vegetation at a point no later in time when it poses a threat to the reliability of the transmission line. Exceptions include vegetation used for designated visual screens, trees of a historic significance, vegetation to control erosion, agreements made at the time of environmental approval for construction, â€¦â€¦â€¦etc.
Agree
Disagree
Clarification is required on the requirements. The frequency and need for inspection is based on a number of factors that include: type of vegetation on a right of way, change in growing conditions and the Transmission Ownerâ€™s clearance standards (i.e., if the clearance standards are well above the Critical Clearance then the risk to reliability may be very low, so why inspect for vegetation clearances on an annual basis?) This being the case, clarification is needed on inspection requirements relative to the overall approach used to manage vegetation clearances. For example, Hydro One conducts routine line inspections on an annual basis and identifies clearance issues. Would this meet the requirements of the standard?
Agree
Agree

Agree
Disagree
We would agree only if the standard is revised to include the removal of incompatible vegetation as outlined in our response to question 3 above. If not, then added direction or requirements are needed to introduce the elements that combine (to a greater degree than exists under the revised standard) reliability and vegetation management. Clearance 1 accomplished this to some degree.
Agree
Agree
Agree
Agree
Agree
Disagree
A statement is needed that this requirement applies to the active right of way. Outside of the active right of way there is no guarantee that this can be achieved. As noted in the question above, it may be very difficult with the first alternative to provide adequate evidence that no encroachment had occurred over the compliance period, as the situation is very difficult to assess along each span to the accuracies (1/100 of a foot) spelled out for the CCZ. It may be more meaningful that the Transmission Owners be able to demonstrate processes, methodologies and actions that can support that vegetation has not entered the CCZ. Another alternative for R4 could then be: Each Transmission Owner shall demonstrate that adequate actions and processes are in place to prevent vegetation from entering the CCZ. The effectiveness of the process can then be evaluated based on methods used for field assessment and performance, i.e., outages and imminent threat reporting. It appears that the second alternative noted above can be combined with R2. It is not clear why there needs to be a separate requirement. Hydro One is not in favour of alternative 3, as this would create added administration with a situation that will be difficult to prove to the accuracy required. LIDAR may be the only means available to provide evidence of a quality needed to produce meaningful statistics, and in many cases this may not be the most efficient use of the limited funding that is available.
Disagree
A further exception would be a sustained outage where the conductor has moved outside of the critical clearance zone. This could occur under conditions of heavy icing, operating outside the line rating or excessive wind. These would not necessarily be the result of a natural disaster. Also, it is recommended that the requirement for R7 be revised to â€œEach Transmission Owner shall minimize (â€œminimizeâ€☐ replacing â€œpreventâ€☐) Sustained Outages of applicable lines due to vegetation falling into a conductorâ€¦.. A fall in is a random occurrence and the likelihood that this would be the cause or contribute to a cascading event is very remote. These types of outages are rare and can be considered similar in nature to an insulator flashover or a hardware failure, which have not been given any association with cascading events. The purpose of the standard is to prevent cascading events and it is suggested that this remain the focus and not introduce other types of outages on a selective basis.
Agree
Please see our comments on question 3.
Individual
David Dworzak
Edison Electric Institute
Disagree

The purpose of the standard should be revised to state 'To maintain minimum clearances sufficient to avoid any vegetation-related Sustained Outages for all applicable conditions.' This is the identical wording taken from Order No. 693, Paragraph 731.
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Disagree
Consistent with previous comments, NERC should respond to FERC Order No. 693 Paragraph 721 regarding compliance audit procedures to identify appropriate inspection cycles.
Disagree
Encroachment without a Sustained Outage should not be construed as a violation. The proposed R4 requirement should be removed. EEI strongly believes that this requirement, if approved, is unenforceable. The alternative, to require implementation of the imminent threat procedure, should be considered as a practical approach. In particular, this concern applies to a requirement to prove that no encroachments have existed. This will require extensive work by field personnel, who will be required to make subjective judgments. In addition, determining actual clearance zones in the field would require a span-by-span analysis to be conducted with the rigor of survey level measurements. Calculations made to determine the clearance zones are based on undefined terms and subject to wide variation. Enforcement authorities will be required to make interpretations. EEI believes that the costs of conducting such work will not deliver sufficient benefit to warrant the requirement. Ultimately, there is no basis for determining whether the theoretical clearance zones included in the proposed standard will increase, or even maintain, an adequate level of reliability as provided by the existing standard.
Agree
Agree
Overall Comments EEI strongly believes that companies are responding assertively to the requirements in FAC-003-1 and that the existing standard is effective in supporting an adequate level of reliability. The central issue with FAC-003-1 and the draft version 2 centers on circumstances

where vegetation encroachments into clearance zones take place and do not result in interruptions. EEI understands that a potentially broad range of interpretations are being applied to the existing standard, resulting in potential violations due to clearance encroachments of any possible design position of the conductor being violations, as well as Sustained Outages. Version 2 should clarify this issue in the context of focusing the industry in the direction that is most effective in establishing an adequate level of reliability. The technical comments provided by EEI seek to address this critical issue. Quantitative analysis on vegetation-related line outages or violations made publicly available do not support the need for a substantive revision of the standard. Analysis needs to recognize a broader range of facts in a consistent manner. Analysis needs to consider whether violations resulted in a Sustained Outage, whether all outages and vegetation encroachment were voluntarily reported prior to enactment of Section 215, or the facts and circumstances surrounding violations. For example, while some entities may perceive a decline in industry performance, it may be that companies are reporting much more completely than in the past. Much more rigorous analysis is needed before concluding that the existing standard must be made tougher. Rather than focusing on whether the standard should be more stringent, EEI believes that the emphasis in the standard development process should focus on practicality, both for field personnel in terms of implementing the standard, and enforceability. Revisions to the existing standard should therefore seek to a) respond to issues raised by FERC in Order No. 693 b) where possible, clarify ambiguities in the requirements, and c) improve industry understanding, practicality, and enforceability. For example, it is impractical to seek development of a â€˜bright lineâ€™ set of performance requirements. The standard needs to recognize both the diversity of the continent in terms of geography, topography, and climate, and the critical need to provide field personnel with workable performance requirements. Bottom line; it is very important to recognize that the ultimate goal of the standard is to ensure that vegetation management is conducted in order to maintain an adequate level of reliability, and the industry is achieving this goal. The standard should aim for increasing clarity in the requirements without sacrificing flexibility, since companies expect high monetary penalties associated with Sustained Outages caused by vegetation. In addition, a continued â€˜zero toleranceâ€™ approach to vegetation management will emphasize operational excellence. Seeking â€˜zero toleranceâ€™ on momentary outages is equivalent to pursuit of operational perfection, which is achievable only at extraordinary expense to customers. Therefore, the Standard will be most effective if its elements encourage proactive behavior and provide incentives for Transmission Owners to identify and address vegetation clearance issues before they result in momentary interruptions or Sustained Outages. Vegetation Outage Data In Order No. 693, Pargraph 732, FERC ordered NERC to collect and analyze transmission outage data to inform development of the revised standard. EEI encourages the drafting team and NERC Standards Committee to request that NERC collect and analyze this critically important information. Such analysis provides an important foundation for determining whether the standard can ensure an adequate level of reliability as required by Section 215. Applicability Order No. 693, Paragraph 708, directs NERC to 'develop an acceptable definition that covers facilities that impact reliability but balances extending the applicability of this standard against unreasonably increasing the burden on transmission owners.' In the order, FERC appears to accept the 200-kv threshold, however, continues to ask about these other critical facilities. EEI recommends that the drafting team develop a definition of 'sub- 200kv critical facilities' for use in the standard. Reliance on Reliability Coordinators for developing their own definition raises the likelihood of inconsistent approaches and applications of the term. In addition, the drafting team should consider whether such critical facilities might require expanding applicability to entities other than Transmission Owners. Annual Plan as a Defined Term In order to aid in compliance enforcement and industry compliance, the term 'annual plan' should be a defined term.
Group
Santee Cooper
Terry L. Blackwell
South Carolina Public Service Authority
Agree
Disagree
The RC should not define applicable lines that are operated below 200 kV. PRC023 requires the Planning Coordinator to define transmission lines operated at 100 kV to 200 kV that are considered

critical to the reliability of the Bulk Electric System. Multiple lists will lead to confusion among electric utilities.
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Disagree
Recommend replacing the word "prevent" in R4 to "monitor". The first alternative that requires immediate removal of vegetation or immediate implementation of the imminent threat procedure would be a Requirement that could be measured. In addition, if an encroachment is found it needs to be eliminated and the first alternative specifies immediate removal. If R4 is left as written, how can you provide evidence that there has been no encroachments within the Critical Clearance Zone.
Disagree
Recommend removing R7 because current and proposed standards do not require the entire right-of-way or Active Transmission Line Right of Way to be clear of vegetation. In this case, a utility should not be penalized if a tree falls from within the right-of-way or Active Transmission Right-of-Way as long they are meeting all the other standards (e.g., minimum vegetation clearance distances). Since fall-ins from just outside of the right-of-way is currently not a compliance issue, it makes sense that a fall-in from within the right-of-way be treated the same. This is especially true for a utility who has elected to acquire a wider right-of-way than another utility. That utility may have a tree(s) growing just inside the right-of-way but still maintains a better clearance distance between trees and conductors than a utility with a narrower right-of-way and no tree encroachment.
Agree
The SDT should clarify that Transmission lines operated at 200 kV and above is for lines that are network facilities. Radial load transmission facilities operated at 200 kV and above should not be subject to this standard as they would not lead to SOLs or IROLs. M2 requires evidence that a TO implemented its imminent threat procedure upon knowledge of a Critical Clearance Zone breach. M4 requires evidence that there were NO encroachments into the Critical Clearance Zone. These two measures are in conflict with one another. If a utility provides evidence for M2 then they are in violation based upon M4. M4 and M5 requires a utility to provide "proof to the negative". These measures should be removed from the standard. R9, R10, M9, and M10 should be removed from this

standard as critical facilities are identified through the PRC standards.
Individual
George Czerniewski
Consolidated Edison Company of New York (CECONY)
Disagree
The phrase "Bulk Electric System" (BES) is somewhat misleading. BES includes transmission voltages greater than 100kV but this Standard addresses transmission lines with operating voltages at or above 200kV and only those lines below 200kV designated by the Reliability Coordinator. Use of the phrase "electric transmission circuits" or something similar rather than BES would reduce confusion.
Agree
CECONY agrees provided that R9 remains the same as is currently written. This states that the Reliability Coordinator, in consultation with the Transmission Owner, shall jointly prepare and keep current, a list of designated applicable lines.
Agree
Agree
Agree
Agree
Disagree
CECONY currently has procedures that mandate response to imminent threats. The Standard should be made more general and not identify the specific actions that shall be taken in the procedure. The second sentence of R1.4 should be deleted and the first sentence should read, 'Require a process or procedure to respond to vegetation-related imminent threats." This adds the necessary flexibility that utilities require and avoids additional redundant processes or procedures from being developed.
Agree
Agree
Agree
Disagree
CECONY is in favor of using the Gallet equations as they provide a more realistic clearance distance for vegetation. We understand and agree that establishing a Critical Clearance Zone (CCZ) would provide the specific area that a conductor could possibly travel through during various field and weather conditions but we do not agree that this is the most practical approach. The main issue is that the wording '...the Critical Clearance Zone is approached by vegetation.....' is very vague and left open to wide interpretation which causes inconsistency and confusion throughout the industry. The CCZ changes throughout the length of each conductor in each span so a field inspector's job and an auditor's job become much more complicated when trying to confirm compliance when vegetation is present in the Actiove ROW. We feel that the time spent trying to measure and calculate the CCZ and then confirm compliance would be better spent initiating a response plan to safely remove the vegetation. The imminent threat procedure would only be implemented if vegetation encroaches beyond a specific distance from the conductor, not as it approaches the theoretical CCZ. Advanced technology would be required if a vegetation approach distance to the CCZ was to be calculated in the field. This is a very costly and time consuming requirement and does not efficiently meet the Standard's goal of ensuring reliability.
Agree
Agree

Agree
Disagree
CECONY disagrees with R4 as currently written. As mentioned in the response to Question 15, performing a field measurement of the CCZ and a field measurement of the vegetation encroaching into the CCZ are complicated, time-consuming efforts. As the CCZ changes along the conductor, so too may the Active ROW dimensions, the vegetation clearances at multiple points, and elevation levels to name a few. Certifying compliance that no encroachments have occurred would be very difficult for auditors and field inspectors. Modern laser technology would have to be deployed to take these measurements and CECONY is concerned that, if an encroachment of the CCZ constitutes a violation, utilities would not consider investing in this technology knowing that multiple violations could potentially be found within a single span. Enhanced reliability is achieved when utilities invest in the best available technology and perform proactive inspections on their systems but, as written, R4 would not effectively motivate a utility to follow through with these initiatives. We recommend that the term 'momentary outage' or the phrase 'all outages' be used in R5, R6, and R7 instead of 'Sustained Outages' to avoid confusion throughout the industry. Momentary outages identify a potential failure of the utility's vegetation management program and stating it directly in the Standard clearly sends the message to utilities that all vegetation outages are unacceptable. In summary, we do not agree that encroachments are violations but we do recommend that when a utility identifies vegetation-related imminent threats and takes immediate action, they report this to their Reliability Coordinator. The Reliability Coordinator (RC) could then identify the utilities that have had multiple issues or have exceeded acceptable pre-established reporting limits which, in turn, would help the RC prioritize auditing efforts. This, in our opinion, would enhance reliability more effectively.
Agree
CECONY agrees that outages caused by the factors mentioned are violations of R5, R6, and R7 but we recommend that either the phrase 'momentary outage' be incuded in the wording or the phrase 'All Outages' replace 'Sustained Outages' to make the requirements clearer.
Agree
CECONY does not feel that, as currently written, the Standard would effectively enhance reliability throughout the industry. We recommend that stricter language be used in the Standard specifically requiring the industry to remove incompatible species on Active ROWs. This should reduce the number of outages resulting from vegetation grow-ins and vegetation fall-ins from inside the Active ROW and help maintain a higher level of reliability. This is currently done at the state level (in NY) and the revised wording in the Federal Standard may help promote consistency industry-wide and avoid confusion. Also, the concept of the CCZ is theoretically strong but it needs to be made simpler for the auditors and field inspectors.
Individual
Tom Mathews and Steve Rueckert
WECC
Agree
Disagree
WECC believes the Regional Entity should remain the proper entity to identify sub-200kV transmission lines subject to this standard. The Regional Entity is in the best position to work with Transmission Owners (TOs) and Reliability Coordinators across the interconnection to determine critical sub-200kV transmission lines.
Agree
Agree
Agree

Agree
Agree
But for clarity, "Imminent Threat Procedure" should be replaced with "Vegetation Imminent Threat Procedure".
Agree
Agree
Agree
Agree
Yes but the wording is ambiguous. Vegetation under a transmission line is always "approaching" or growing towards the transmission line. Entities should define a specific distance greater than the Critical Clearance Zone when they are required to implement their Imminent Threat Procedures.
Agree
Agree
Agree
Agree
Yes, R4 as written provides clear guidence to TOs on the minimum radial distance, dependant on line voltage that vegetation is allowed to approach energized conductors. These industry standardized distances will ensure a level of reliability equal to or better than FAC-003-1.
Agree
However reporting requirments are not identified in the standard. WECC believes that sustained outages caused by vegetation should be reported to the Regional Entity using the existing reporting requirments in FAC-003-1
Agree
Reporting requirments are not identified in the standard. WECC believes that sustained outages caused by vegetation should be reported to the Regional Entity using the existing reporting requirments in FAC-003-1 (Transmission Owners report outages to the Regional Entity). Reports of sustained outages to the Reliability Coordinator should be made for reliability purposes and not compliance purposes. The Reliability Coordinator should not be required to report vegetation outages of individual Transmission Owners to the compliance department.
Individual
Sreenath Thota
Arizona Public Service Company
Disagree
APS suggest the following change; To improve the reliability of the Bulk Electric System by preventing vegetation related outages. This is a reliability standard APS would suggest removing "that could lead to widespread cascading failures" from the purpose statement.
Agree
Agree
Agree

Agree
Clarification is required on exactly what an inspection is, which should perhaps be outlined in the white paper. There are areas where inspections are not necessary at all, such as lines over a parking lot, or in a remote desert area. APS needs some assurance that this inspection will not constitute a dedicated, comprehensive vegetation management inspection. Inspections are currently often part of a routine line patrol, where the forester or lineman looks for vegetation concerns in addition to undertaking maintenance work. Therefore, the Transmission Owner needs the ability within their TVMP to define what an inspection is in the context of their utility operations.
Disagree
The document would benefit from keeping the two requirements together, since they relate to the same topic. Under the new wording in R1, the TVMP no longer has a requirement to include objectives. However, there is a phrase in R1.3 to â€œsupport the objectivesâ€¦and methodologiesâ€¦outlined in theâ€¦program.â€☐ To be consistent with R1.3, APS recommends that R1.1 be reworded to specify the methodologies and objectives that the Transmission Owner uses to control vegetation.
Agree
APS agrees with 1.4, with the following qualification: Any standard that is developed should not contain advisory-type languageâ€"it should be declarative in tone. For example, in R1.4, the ending clause that begins â€œâ€¦and may include actionsâ€¦â€☐ should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program.
Agree
Disagree
APS disagrees with removal of clearance one. Clearance one should be achieved at time of maintenance which is part of the vegetation program. This gives leverage with dealing with state and federal agencies, tribal and private landowners. This isn't a fill in the blank requirement, however it should be based on sound science in regards to vegetation management. A professional arborist/forester can determine the appropriate amount of vegetation that needs to be obtained at the time of maintenance. APS suggest the following language change for clearance 1. The Transmission Owner shall maintain ROW on Federal, State, Tribal and Private lands in accordance with ANSI-Standard A300 (Part 1)-2001 and (Part 7)-2006 in consultation with companion publication Best Management Practices: Integrated Vegetation Management, 2007. If all utilities followed this standard this would increase the reliability of the bulk electric system and reduce the risk of vegetation outages.
Disagree
APS disagrees with the removal of personnel qualifications. The person responsible for vegetation management program should have experience and training in vegetation management and system operations. The International Society of Arboriculture has an ISA Certified Arborist and Utility Specialist certification. This requires the credential holder to have minimal qualifications before sitting for the certification and on going training to maintain the credential. The industry has already responded by providing the information as part of the current standard FAC-003-1. It makes no sense to remove personnel qualifications from the revision.
Agree
Agree
Agree
Agree
APS understands that itâ€™s possible to have a schedule and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the schedule is kept together with the requirement to implement it.
Disagree

APS agrees with alternative one.The new requirement in R4 stipulates that the Transmission Owner is in violation if an encroachment of the CCZ occurs at any time. However, the CCZ changes with each foot of the transmission line from the insulator to the mid-span, depending on loading, actual operating temperature, wind loading, ice loading, maximum design rating, maximum operating load, and so on. Further, Measure M4 requires that the Transmission Owner has evidence demonstrating there were no vegetation encroachments into the CCZ. These requirements may result in having to LIDAR the lines annually, to prove that trees have not encroached upon the CCZ. This would be an extremely onerous and expensive requirement for utilities. APS strongly supports the alternative to R4 as recommended in the Comment Form (#15), which is to require immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the CCZ, thereby proactively preventing an outage. This means a violation would occur only if the imminent threat process is not successfully implemented. This alternative is essentially the same as R2. Therefore, APS recommends removing R4 from the standard entirely.
Disagree
APS strongly recommends that the requirement under R7 be changed from â€œshall prevent sustained outagesâ€□ to â€œshall minimize sustained outages due to vegetation falling into a conductor.â€□ We note that the word â€œminimizeâ€□ was present in earlier drafts of the document. We are concerned about the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. This could lead to an incident where utilities are charged unreasonably â€“ for example, for an outage from a tree that was one foot within the active ROW line. We should not be held liable when reasonable due diligence is practiced. Further, it is not economically feasible for utilities to survey every ROW in the U.S. and Canada to determine precise clearance zones.
Disagree
APS understands that itâ€™s possible to have an annual plan and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the plan is kept together with the requirement to implement it.
APS has a comment to NERC on picking the standard drafting team. FAC-003 is a vegetation management standard not an engineering standard. The team members should have been chosen based on managing the vegetation program not because they were engineers. Any standard that is developed should not contain advisory-type languageâ€"it should be declarative in tone. For example, in R1.4, the ending clause that begins â€œâ€¦and may include actionsâ€¦â€□ should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program. APS supports the development of this white paper as a way to help ensure consistent interpretation of the standard. Perhaps the lack of such a paper in the first version of the standard contributed to the varying interpretations by the auditors. The utilities understand however that this document is not a legal document and is not binding.
Group
Southern Company
Roman Carter
Southern Company Transmission
Disagree
The initial FAC-003-1 drafting team had a particular reason for not using Bulk Electric System for fear of it being widely recognized to characterize the entire networked transmission system. This reason was to limit possible confusion with the applicability of the Standard. The Bulk Electric System definition includes all lines of the grid operated at 100 kV and above. This term also does not necessarily include lines of any voltage class that are radial and directly serving load. Use of this term in lieu of â€œelectric transmission systemsâ€□ has the potential to cause additional confusion to the industry.
Disagree
The use of the Reliability Coordinator as the entity for identifying sub-200 kV lines is inconsistent with the approach used in other NERC standards, such as PRC-023. Other NERC standards utilize the Planning Coordinator or the RRO as the entity. We feel the Planning Coordinator would be the appropriate entity for identifying sub-200 kV lines covered by FAC-003-2.

Agree
Agree
Agree
Agree
Disagree
The standard requirement, as written, requires the "immediate notification" of the operator. This standard requirement could be interpreted to mandate that this notification take place prior to any other action. There could be times that this communication would take up valuable time needed to relieve the immediate threat. The requirement should be modified to list examples of appropriate actions that could be taken. The Transmisison Owner should be allowed the flexibility of developing a communication process that ensures timely notification of a threat and the proper channels of communication that will be utilized in making the notifcation. The present wording in the standard alone suggests the individual observing the threat in the field is directly responsible for communicating with the Transmission Operator while the whitepaper tends to be more flexible. The Transmission Owner may wish to have the vegetation contractor notify the Transmisison Owner's forester who in turn will notify the Transmission Operator. While the whitepaper does an adequate job describing acceptable responses, the standard does not. It is recommend the standard, VSL, and RSAW better explain what is an acceptable response to the TOP. The requirement then goes on to address specific actions the operator "may" take in response to the notification. The imminent threat processs should be limited to the steps taken to notify the Transmission Operator in a timely manner. FAC-003 is not the appropriate place to address Transmission Operator decisions resulting from notification of a threat to the system.
Agree
Agree
Agree
Disagree
As written, R2 requires activation of the imminent threat process when the Critical Clearance Zone (CCZ) is "approached" by vegetation. The term "approach" is vague and open to interpretation. Since vegetation is dynamic in nature, it is constantly "approaching" any pre-defined zone. There could also be many examples given of encroachments into the theoretical CCZ that would neither threaten the transmission line conductor nor cause a reduction in the capacity of the transmission line. This concept would be better suited to be a â€œtrigger pointâ€☐ that, if found, would be incentive for the Transmission Owner to take immeidate action or ensure future action occurs on schedule. This action may be as urgent as implementation of the immediate threat procedure or as non-urgent as making sure that the upcoming maintenance on that line is scheduled appropriately. We are concerned this revision of FAC-003 continues to take a zero tolerance approach to compliance, which is contrary to the philosophy utilized in other NERC standards. A state of non-compliance should not exist simply because vegetation encroached within a pre-defined zone by a fractional inch, but only when an event, such as a sustained outage, occurs due to the Transmssion Owner's failure to maintain adequate clearance between conductors and vegetation.
Agree
Agree
Agree

Disagree
The Critical Clearance Zone is a concept that adequately describes the salient functionality a Transmission Owner must consider when determining acceptable clearances. However, the practicality of a requirement that forbids even one encroachment in the Critical Clearance Zone presents a problem for not only the field personnel doing the vegetation work, but also the Regional Entity that must enforce the requirement. This zone changes not only from one span to another, it also changes at each location along each span. The reality is that the difference in encroaching into the zone and not encroaching into the zone is a matter of a fractional inch. In order to prove non-compliance or to defend compliance at a particular site, all vegetation work would have to be postponed for survey accuracy equipment and appropriately trained personnel to be brought to the site, measurements and calculation to be made and consequently a determination rendered. This hardly seems worthwhile when the vegetation could simply be cut, the threat removed and the vegetation work could continue on down the transmission line. As stated in a previous comment, there could be many examples given of encroachments into this theoretical zone that would neither threaten the transmission line conductor nor cause a reduction in the capacity of the transmission line. This concept would be better suited to be a â€œtrigger pointâ€☐ that, if found, would be incentive for the Transmission Owner to either take immediate action or ensure future activities are appropriately scheduled and implemented. This action may be as urgent as implementation of the immediate threat procedure or as non-urgent as making sure that the upcoming maintenance on that line is scheduled appropriately. If a sustained outage occurs due to an encroachment, the outage should be the compliance measure.
Agree
Disagree
While we agree in principle, we feel Requirement R8 as written is â€œopen endedâ€☐ and could be interpreted to be in conflict with the â€œActive Rights of Wayâ€☐ concept. Clarifying the intent for the annual plan to focus on the Active Rights of Way will prevent incorrect interpretations. We suggest that the Requirement be reworded to read: Each Transmission Owner shall implement its annual work plan for vegetation management within the Active Right of Way to accomplish the purpose of this standard within the extent of its easements and or legal rights.
We would like to re-emphasize our concern over the zero tolerance philosophy of FAC-003-1 which is continued in this proposed revision. FAC-003 has been singled out as the only zero tolerance NERC standard. Compliance should not be based on the encroachment of vegetation into a theoretical, pre-defined zone, but on the occurrence of a sustained outage, as stated in the document's Purpose Statement. We agree with the philosophy utilized in other NERC standards where a clearly discernible compliaince event signals a review of the Transmission Owner's plans, policies, and procedures to determine the effectiveness of the entity's programs and spirt toward complaince. Applicability Section 4.2 describes the Facilities pertinent to this Standard. Recommendation is to restructure the sentence by relocating the parenthetical phrase: Transmission lines operated at 200kV or higher, and transmission lines operated below 200kV designated by the Reliability Coordinator as being subject to this standard (â€œapplicable linesâ€☐) including but not limited to those that cross lands owned by federal, state, provincial, public, private, or tribal entities. Requirement R3 Recommend rephrasing to say: Each Transmission Owner shall conduct vegetation inspections of all applicable lines in accordance with the frequency specified in its transmission vegetation management program. Requirement 10 The standard does not mention whether or not the results of this specific assessment methodology are supposed to be compiled and maintained. The resulting information could be labeled as sensitive and possibly critical since the loss would place the grid at an unacceptable risk of instability, separation, or cascading failures. If the resulting information becomes auditable (subject to discovery and posting) then precautions must be taken that are comparible to those designed to preserve the integrity of critical assets or critical cyber assets. We would like to express our sincere appreciation and thanks the drafting team for their efforts.
Individual
Patrick Brown
PJM Interconnection
Disagree
The RC or PC should not play a role in the vegetation management standard. All TOs need to ensure

they have a vegetation program to avoid unnecessary tripping of transmission lines, at any voltage levels and regardless of their impacts on the BES. Identification of critical facilities is not a part of this standard; it belongs to other standards that deal with SOL/IROL calculations, SPS, protection and critical infrastructure protection. R9 and R10 should be removed from the standard.
the current version of this standard, FAC-003-1, kept the subject of vegetation outside of the Rights of Way in the standard. Why are outside of Rights of Way vegetation issues not mentioned in FAC-003-2, or some responsibility for looking for outside of Rights of Way imminent threats or issues requiring corrective action plans not addressed?
Individual
William T. Rees
Baltimore Gas & Electric Company
Agree
Agree
The documented method to assess the reliability significance of sub-200 kV lines referenced in R10 should be put out for comment by the Reliability Coordinator to the regulated entities and FERC/NERC before it is finalized.
Disagree
I agree with the simplification of the language, but I am uncomfortable with the definition of Active Right-of-Way (R/W). The definition in FAC-003-2 and the examples used in the white paper continue to leave room for interpretation, particularly with respect to the example where only one circuit is installed on a double circuit tower. Moreover, there may be circumstances where the Active R/W is relatively narrow and the utility has an Inactive R/W or otherwise owns land adjacent to the Active R/W that can be maintained to protect the facilities from grow-ins. Consequently, consideration should be given to require utilities to protect lines from grow-ins into the CCZ regardless of whether or not the R/W is Active or Inactive as long as the utility has the legal ability to do the necessary work.
Agree
Agree
Disagree
See response to question no. 17.
Agree
This requirement references Danger trees which according to ANSI A-300, Part 7 is any tree that could fall on the conductor. Should this more appropriately be changed to Hazard tree which is a

structurally unsound tree? It might be helpful if an imminent threat were defined, e.g trees that are presently encroaching in or near the CCZ, or trees that by virtue of their hazardous condition appear to be likely to fall into or near the CCZ in the near future. (or just leave the explanation to the White Paper)
Agree
Agree
While I may agree with the removal of this requirement strictly for reasons of simplification and self-determination, the current requirement forced utilities to structure their TVMP to develop safeguards to keep trees from encroaching into the Clearance 2 envelope. The proposed change will leave the clearance issue beyond the CCZ unaddressed. Responsible utilities will take the appropriate measures and other utilities will not.
Agree
Similar to the response to no. 9, the end result is what counts and each utility will be responsible and accountable for their actions. Qualifications unlike clearance requirements, are far-removed from results and can easily be left unaddressed in the new std.
Agree
Again, each utility is responsible and accountable for it's actions. The Gallet clearances are a much better approximation of a true spark gap than the present requirement. Without a clearance one requirement, the closer tolerance produced by the Gallet equation will leave little room for error when a line is at or approaching it's max. engineered sag. When vegetation gets in the new CCZ (if adopted), it will be likely that an outage will be imminent. With the present clearance 1 and clearance 2 requirements, there is more of a buffer for encroaching vegetation.
Disagree
As noted in 11 above, the Gallet equation would appear to be a much closer approximation of the actual spark gap/flashover distance. It seems as though the new std. is making the protective zone around the conductors smaller by replacing the Clearance 2 requirement with the CCZ, while at the same time eliminating any other type of consideration for how much clearance needs to be achieved while trimming. All things being equal, if the only demarcation for when vegetation is a threat to the lines is the clearance 2 or CCZ areas, it would make sense to have this area be larger rather than smaller. Accordingly, I would recommend that the Clearance 2 value continue to be used instead of the Gallet equation-created CCZ.
I have no expertise to respond to this question.
Disagree
If frequency of inspections are required to be specified, it is implied that the inspections will follow. I suggest that R3 be eliminated and R1.2 be reworded to say: "Vegetation inspections shall occur at least once per year, or more frequently as dictated by local and environmental factors. Specify the frequency of when vegetation inspections will occur."
Disagree
One concern with the proposed wording is that the verbiage seems to provide a loophole that will count any fallen tree, or tree with the potential to fall from inside or outside of the R/W (that doesn't meet the criteria in footnotes 4 & 5) that passes or could pass through the CCZ, and that may or may not cause an outage, would qualify as a violation in the std. There is no other language that I can detect in the std. that counters this point. Determination of whether or not a fallen tree, or tree with the potential to fall would qualify would be predicated upon height measurements of the fallen or standing tree(s) relative to the CCZ at max. engineered sag. An alternative wording suggestion is: "Each Transmission Owner shall prevent encroachment within the Critical Clearance Zone of it's applicable lines associated with trees that meet the criteria for grow-ins from on or off the Active right-of-way. Fall-ins from inside or outside of the active right-of-way are not applicable to this sub-requirement." If the occurrence is a violation, reporting of the incident will be an ethical issue and rely on the honesty of the inspector or whomever finds the problem. If it's not a violation, it will be more likely that the incident will be reported and can be treated as "Near Miss' reports are with respect to safety incidents - they provide valuable input to help forestall future more serious incidents. Consequently, I recommend that no violation occur as long as the 'Imminent Threat Procedure' is implemented. Further, if there is no violation associated with Imminent Threat Procedure

implementation, I would suggest that falling or standing trees orginating from within the active right-of-way that encroached or could encroach in the CCZ be added to the requirement to enhance the 'Near Miss' datapool.
Agree
Disagree
As in question no. 14 above for R1.2, it would seem to make more sense to combine R1.3 & R8 as follows: "Require development and implementation of an annual plan thatâ€¦."
The Applicability Section of the Reliability Standards (4.2 Facilities) defines the Transmission Lines (Applicable Lines) that must comply to the reliability standard. This section should clearly state that the scope is limited to the facilities that are Bulk Electric System facilities consistent with the Bulk Electric System definition as defined by the Regional Entity. Regarding M5, M6, M7: The intention of these paragraphs is unclear to me as written. At first glance, it appeared that the paragraphs were asking for a negative to be proven, e.g. prove that you didn't have any tree-related outages. Anther possible meaning is that utilities have to justify the cause of any outage that may occur. As such, the burden of proof is on the TO to provide evidence that an outage was not caused by trees. If an outage were to occur but the TO could not find any evidence of the cause, the wording in these paragraphs suggests that by default, the outages will be classified as tree-related. If these paragraphs are intended to assign an outage cause to an outage that has already occurred, then perhaps they could be reworded to say something to the effect of: "TO shall provide results of investigation into all transmission outagesâ€¦â€¦" If these paragraphs are not intended to assign an outage cause to an outage that already occurred, but to provide a mechanism to report outage performance that is currently covered in M3 and M4 in FAC-003-1, then perhaps they could be reworded to say something to the effect of: "TO shall provide documentation of tree-related outage performance on a quarterly basis. Investigation results for unknown outages shall also be provided on a quarterly basis." Or as one last suggestion, the wording could simply be: " The TO has evidence that there was a Sustained Tree-related Outageâ€¦. Regarding the Tech. Reference, I thought that overall it was helpful and will be valuable to help provide guidance for TVMP development and implementation. The area that covers the Active/Inactive R/W should be more clearly explained and illustrated, particularly with respect to the towers with space for another circuit on one side of the structures.
Individual
Greg Rowland
Duke Energy Corporation
Disagree
Duke disagrees with changing "electric transmission systems" to "Bulk Electric System" because this creates the potential for confusion or indiscriminate expansion of the scope of applicability to 100kV facilities which may not have an impact on network system reliability. Using "Bulk Electric System" confuses the applicability of the standard. Duke believes that Section 4.2 has the specificity to clearly designate any applicable lines. Thus, the term "electric transmission systems" is appropriate.
Disagree
Duke believes that the Planning Coordinator is the appropriate entity to identify any sub-200 kV facilities that this standard should apply to. Of note is the time frame â€“ once a sub-200kV line is designated, then the TO has 12 months before the line is subject to the standard. This coincides with the longer term view of the Planning Coordinator.
Agree
Agree
This is a good change from a compliance perspective; the documentation requirements can now be assigned lower VRFs than the implementation requirements.
Agree
Agree
Disagree

Duke believes that Transmission Owners should have a Vegetation Imminent Threat Procedure, and "Vegetation Imminent Threat" should be a defined term, defined as: "Vegetation observed in the field encroaching upon a conductor within a distance that is twice the Gallet clearance distances referenced in Table I of the draft standard FAC-003-2." In this case, the threat would require an immediate response and would include communication to the Transmission Operator. From there, the actions that the operator decides to take will be dependent on the incident and system conditions. We do not need to be prescriptive with this requirement but rather allow the Transmission Operator and appropriate field personnel the flexibility to make the right decisions to safely, promptly and appropriately remove the vegetation threat. From a Transmission Owner's perspective, many situations can constitute an imminent threat but this approach will clearly define a "Vegetation Imminent Threat" as it relates to the Purpose of this standard. See our related comment on #11 below.
Agree
Agree
Agree
Disagree
No. Duke believes that the CCZ is a good theoretical concept to aid industy in understanding the overall movement of conductors, but it is an impractical concept for field application. Due to the variability in the size of the CCZ as you move along a conductor, as well as changes from span to span or even line to line due to design parameters, loading or weather-related issues, the CCZ concept should not be tied to an imminent threat procedure. Vegetation approaching the CCZ does not constitute an imminent threat. It may be years before this vegetation ever gets to a proximity distance from the conductor to be within a "spark-over" distance as defined by the Gallet equations. Requirement R2 should support the purpose of this standard by requiring implementation of the Vegetation Imminent Threat Procedure when the Transmission Owner has visual, field knowledge that vegetation is encroaching upon a conductor within some specific distance that is a multiple of the Gallet distances referenced in Table I of FAC-003-2 (to be conservative we suggest two times the Gallet distances). Failure to implement the Vegetation Imminent Threat Procedure in such instances would be a violation of R2. As R2 is currently stated, a Transmission Owner cannot comply with R2 unless the imminent threat procedure is continuously being implemented, because vegetation that is growing is always approaching the CCZ. "Approaching the CCZ" cannot be the trigger for implementation of the Vegetation Imminent threat Procedure. Instead, the trigger should be an encroachment within an observed distance from vegetation to conductor that is twice the Gallet distances in Table I. Requirement R2 could be reworded as follows: â€œEach Transmission Owner shall implement its Vegetation Imminent Threat Procedure when the Transmission Owner has knowledge, obtained through normal operating practices or notification from others, that vegetation is encroaching upon a conductor within a distance that is twice the Gallet clearance distances referenced in Table I." Using a multiple of the Gallet distances provides a safety factor. Assessing a violation for failure to appropriately implement the Vegetation Imminent Threat Procedure or for a sustained vegetation-related outage incents the proper behavior.
Agree
Agree
Agree
Disagree
The second bulleted alternative above is the best approach, but Duke believes it should be improved by changing the imminent threat trigger from "encroachment of the CCZ" to "encroachment within some observed, field distance that is a multiple of the Gallet distances referenced in Table I". We have recommended changes to accomplish this in Requirement R2 (see our response to Question #11 above), and R4 should simply be deleted. While the CCZ is valuable to understanding the movement

of conductors, it cannot be readily applied in the field. This field application challenge is noted in the Technical Reference Document (pages 29 & 30). The way R4 is currently stated, the Transmission Owner would be in violation of R4 for any CCZ encroachment not due to natural disasters or human or animal activity. This would include a tree falling from outside the right of way corridor that passes through the theoretical CCZ. Furthermore, Transmission Owners would be required to self-certify compliance with R4. The technological requirements for accurately certifying compliance would be impossible to administer. Clearly the approach of assessing violations for CCZ encroachment is unworkable. Likewise, the third alternative listed above is untenable. The tiered approach could have a mitigating effect on violations, but it would require the same inspection effort and postponement of vegetation management that makes the first alternative unworkable. Both the first and third alternatives would require very significant additional expenditures for surveys and documentation in an impossible attempt to certify compliance - money that would be better spent controlling vegetation.
Agree
Agree
Duke agrees with the requirement to implement the annual work plan, but recommends striking the words "within the extent of its easement and/or legal rights". The emphasis for this requirement is to execute the annual work plan. The white paper already speaks to the point that it is a best practice for utilities to exercise their legal rights. If we agree that the goal is to prevent outages, then we can simply end this requirement with "accomplish the purpose of the standard". Each TO will be accountable to manage compliance with this standard.
FAC-003-1 lacks clarity that is essential for understanding what is necessary for compliance. The proposed FAC-003-2 needs to be simplified to aid with field implementation and compliance interpretation. Currently, it does not provide the clarity and simplification needed by Transmission Owners and regulatory bodies to enhance reliability.
Group
IRC Standards Review Committee
Charles Yeung
Southwest Power Pool
Disagree
We do not see the role of an RC or PC in a vegetation management standard. All TOs need to ensure they have a vegetation program to avoid unnecessary tripping of transmission lines, at any voltage levels and regardless of their impacts on the BES. Identification of critical facilities is not a part of this standard; it belongs to other standards that deal with SOL/IROL calculations, SPS, protection and critical infrastructure protection. R9 and R10 should be removed from the standard.

Group
E.ON U.S.
Brent Ingebrigtson
E.ON U.S.
Disagree
The definition of the Bulk Electric System generally does not include radial transmission lines directly serving load and, in addition, includes all lines operated at 100 kV and above. Use of the term Bulk Electric System will cause unnessesary confusion to the industry concerning applicability of this standard. Therefore, we recommend the continued use of the undefined term "electric transmission systems."
Agree
Agree
Agree
Agree
Disagree
The Requirement as written is too prescriptive and is open to interpretation, from an audit perspective, with use of the term â€œimmediateâ€☐ communication and a partial list of activities. Many conditions or threats, requiring immediate removal, would not require communcation with the Transmission Operator, who is not an applicable entity for this standard. We suggest that R1.4 be deleted. Since this is a "zero tolerance" standard any Transmission Owner will remove any discovered threats to prevent outages. If R1.4 is not deleted, we believe that imminent threats should be a defined term. The definition should be as follows: â€œImminent Threat: A vegetation condition which, if not addressed, will place a transmission line at a significant risk of a Sustained Outage.â€☐
Agree
Agree
Agree
Disagree
E.ON U.S. suggests that R2 be deleted. Since this is a "zero tolerance" standard any Transmission Owner will remove any discovered threats to prevent outages. While we agree that the implementation of an imminent threat procedure may be a valid concept, visualization of the Critical Clearance Zone and determining an approaching encroachment is a practice in application of theoretical conductor locations in real time.
Agree
Agree
Agree
Disagree
The concept of the Critical Clearance Zone is useful as a mental model to visualize required vegetation management work. While this is a good conceptual tool to drive consistent terminology and proper vegetation management practices, it remains theoretical in nature and impractical to measure on a

span by span basis. The complexity of determining an encroachment into the Critical Clearance Zone is overly burdensome due to the need for survey accuracy measurements and engineering evaluations. In addition, this complexity leads to questions about the ability to audit this requirement. These complexities introduce reliability and audit issues when encroachments into this conceptual area are defined as violations. We believe the Sustained Outage, as defined by other measures in this standard, should be the non-compliance measure. We suggest that the Critical Clearance Zone concept be kept in the technical white paper and that all references to the Critical Clearance Zone be removed from the body of the standard.
Agree
Disagree
E.ON U.S. believes that the Requirement, as written, is â€œopen endedâ€□ and could be interpreted to be in conflict with the "Active Rights of Way" concept. Clarifying the intent for the annual plan to focus on the Active Rights of Way will prevent incorrect interpretations. We suggest that the Requirement be reworded to read: â€œEach Transmission Owner shall implement its annual work plan for vegetation management within the Active Right of Way to accomplish the purpose of this standard within the extent of its easements and or legal rights.â€□
Individual
Michael Pakeltis
CenterPoint Energy
Agree
Agree
Disagree
The term "Active Transmission Line Right-of-way" is not defined in sufficient detail in the Definition of Terms Used in the Standard section to know how to apply the Requirements. The term causes a circular reference problem with the term "Critical Clearance Zone" that refers to the "limits of the Active Transmission Line Right-of-way" which has no specific definition as to its limits within the proposed revised Standard. There is an attempt to differentiate between the "Total R.O.W." and the "Active R.O.W." portion by using the phrase "occupied by active transmission facilities", but no specific limits of such occupation are included within the definition. Are "active transmission facilities" only the physical energized conductors as-is, where-is? Does "occupied" include the conductor vertical and horizontal movement envelope and any horizontal and vertical electrical clearance as well? Does the term "Active Transmission Line Right-of-way" refer to the legal limits of the right-of-way? The new R8 includes the phrase "within the extent of its easement and/or legal rights" which seems to support that definition. The phrase "a strip of land" seems to refer to a metes and bounds description, but how is that relevant when no specific land space is defined, such as with a railroad occupation or Corp of Engineer's permit? On page 16 of the Technical Reference, there is a reference to the Bramble and Byrnes wire-border zone technique. The wire zone is defined in the Technical Reference as "the section of a utility transmission right-of-way directly under the wires and extending outward about 10 feet on each side". Are the limits of the "Active Transmission Line Right-of-way" intended to be equivalent to the Bramble and Byrnes wire zone, or is the Transmission Owner to use its discretion to define the limits? The examples in the Technical Reference document do not define the limits of the "active transmission facilities" either. The "Active R.O.W." limit in Figure 1 and Figure 3 is arbitrary. Figure 2 is supposed to display an edge zone for vegetation to exist, which implies an "Inactive R.O.W" portion, but no such zone is defined. Figure 1 also has trees shown inside the "Total R.O.W." and within the "Inactive R.O.W." that are tall enough and close enough to be within falling distance of the active transmisssion line which seems averse to R7 for vegetation falling into a conductor when the Transmission Owner likely has legal rights to remove them if they are within the "Total R.O.W." and are within falling distance. The interpretation of M7 will be difficult in this case without a specific method to define the "Active R.O.W." portion of the Total R.O.W. We recommend deleting the confusing terms "Active Transmisssion Line Right-of-way and "Critical Clearance Zone" and returning to the prior Clearance 2 Requirement with the newly specified minimum clearances from Table I of

Attachment 1 as an alternative approach should the definition of minimum vegetation clearance distances remain integral to the Standard.
Disagree
Additional revisions are needed to clarify the requirements. For instance, R1.3 refers to "the objectives" of the TVMP, which are no longer a required element and are not specified in M1.3. Reference to "the objectives" should be deleted. The last sentence of R1.3 should read: "It shall use the methodologies outlined in the transmission vegetation management program." R1.4 requires a process for a response to an "imminent threat of a vegetation related Sustained Outage", but R2 refers to implementing an "imminent threat procedure" to "prevent an encroachment of the Critical Clearance Zone". The requirement and the implementation should both refer to an "imminent threat of a vegetation related Sustained Outage".
Disagree
The Standard and the Technical Reference provide no specific justification for defining a 1-year inspection frequency and is abritrary. The requirement itself does not take into account "local and environmental factors". Since the type of inspection is not specified within the Standard, a frequency of at least once per calendar year is currently workable for CenterPoint Energy, but it may not necessarily be appropriate for Transmission Owners with sparsely vegetated service territories. The Technical Reference for R1.2 should state, "the Transmission Owner is given discretion as to the inspection method", and "that while the inspection frequency is specified, it is not the intent of the Standard that all vegetation be maintained on the same frequency". For example, CenterPoint Energy currently utilizes a 5-year ground-based inspection cycle coupled with a 5-year cycle for vegetation maintenance, and performs a supplemental annual aerial inspection.
Agree
See comments to Q4 above as well.
Agree
Disagree
Since there is no longer a reference to defined clearances in the Standard, it is unclear under what specific "constrained" conditions R1.5 applies. R1.5 does not have a sister requirement for implementation within the Standard which implies it has a diminished value. R1.5 and M1.5 should be deleted as a requirement and measure, but should be footnoted as best practice as was ANSI A300 in R1.1.
Agree
Designation of Clearance 1 is not required to meet the purpose of the Standard.
Agree
Designation of Personnel Qualifications are not required to meet the purpose of the Standard.
Agree
We agree with replacing IEEE 516 standard distances with the Gallet equation standard distances. However, the term "Critical Clearance Zone" refers to the "limits of the Active Transmission Line Right-of-way" which has no specific definition as to its limits within the proposed revised Standard. (See comments to Q3 above.) R2 should be reworded to coordinate with R1.4. (See comments to Q4 above.)
Agree
Agree
Agree
Disagree
It is not reasonable to expect Transmission Owners to devote resources, both human and financial, to prove that vegetation never encroached into the Critical Clearance Zone, anytime-anywhere. R4 and M4 should be deleted. R2 and M2 are sufficient in ensuring a level of reliability equal to or better than FAC-003-1 with some minor wording changes to adopt similar wording of the alternative to R4 that

was considered by the drafting team that includes "immediate implementation of the imminent threat procedure" for imminent threats of a vegetation related Sustained Outage in lieu of a nebulous "encroachment of the Critical Clearance Zone". According to the Technical Reference, it is "nearly impossible to field correlate and accurately 'superimpose' the Critical Clearance Zone around the conductor". It not likely that the Transmission Owner will know when the Critical Clearance Zone is approached through field observation. The previous Clearance 2 provided for a specific radial clearance from the conductor that was much easier to observe. (See comments to Q3 above.)
Agree
We agree with the exemptions; however, R6 and R7 refer to an "Active Transmission Line Right-of-way" which is not defined as to its limits, so M6 and M7 cannot be determined by definition. See comments to Q3 above relating to the definitions and the examples in the Technical Reference.
Agree
R8 requires implementation of the annual work plan "within the extent of its [the Transmission Owner's] easement and/or legal rights." All measures and compliance should be determined on this basis as well. This concept should also be carried through the definitions for "Active Transmission Line Right-of-way" and "Critical Clearance Zone", or for any definition of clearances should the Standard continue to utilize such terms.
The proposed FAC-003-2 has gone FAR beyond what was contemplated by the Commission in FERC Order 693 and equates to a total re-writing of the Standard for no apparent reason. The Commission's determination dealt with the following areas: (1) applicability; (2) inspection cycles; and (3) minimum clearances on National Forest Service lands. For instance in Paragraph 729, the Commission states, â€œAs proposed in the NOPR, the Commission approves Reliability Standard FAC-003-1 with no proposed modification on the issue of clearances. The Commission reaffirms its interpretation that FAC-003-1 requires sufficient clearances to prevent outages due to vegetation management practices under all applicable conditionsâ€¦.â€□ Rewriting the minimum clearances introduced a new set of confusing definitions, and further burdens the Transmission Owners with new documentation requirements with little if any benefit when compared to the Clearance 2 concept in the existing Standard. A preferred approach would have been to incorporate the following few items into the existing Standard: (1) the RC versus the RRO; (2) the designation of a specific inspection frequency; (3) the Gallet equation; and (4) the applicability to National Forest Service lands. We agree that the removal of requirements for quarterly reporting of outages, Clearance 1, and personnel qualifications reduces the burden on the Transmission Owners and does not affect the purpose of the standard to prevent vegetation outages. The Standard could meet its purpose and be streamlined by considering the following changes: 1. Delete the new terms and definitions for "Active Transmission Line Right-of-way" and "Critical Clearance Zone" and revert back to a Clearance 2 requirement while replacing the IEEE 516 standard distances with the Gallet equation standard distances. 2. Delete R2, M2, R4 and M4 which refer to the "Critical Clearance Zone" and rely on R5, M5, R6, M6, R7, and M7 which refer to the prevention of Sustained Outages. 3. Delete R1.5 and M1.5 as a requirement and measure, but footnote the "interim corrective action process" as a best practice as was ANSI A300 in R1.1.
Group
Bonneville Power Administration
Denise Koehn
Transmission Reliability Program
Agree
Agree
Disagree
R1: BPA understands that version 2 clearly states that the Critical Clearance Zone does not extend beyond the Active Transmission Right of Way. The Technical reference provides examples of active and inactive portions of corridors. BPA feels this list of examples is not exhaustive and therefore the technical reference language should be changed to read, "Examples of active and inactive portions of corridors include, BUT MAY NOT BE LIMITED TO:" Also, since it is clearly stated on page 2 of the Standard, that the Critical Clearance Zone shall not extend beyond the limits of the Active

Transmission Line Right of Way, and that these limits are not specifically defined because they may vary by circumstance, the definition of Active Transmission Line Right of Way on Page 2 of the Standard should include a statement that the actual physical limits of each Active Right of Way will be determined by the Transmission Owner. R1.1: BPA recommends retaining the version 1 language of "objectives, practices, approved procedures, and work specifications" as it is more instructive in what is expectied of a TMVP then the version 2 replacement language of "methodologies."
Agree
Agree
It would be helpful to clarify what is expected in regards to what constitutes an inspection. This could be done in the technical reference. Some Transmission Operators inspect vegetation as part of line patrol that focuses on more than just the condition of vegetation along the Right of Way. It should be clear that the Transmission Owner, though required to complete a inspection frequency of at least once per calendar year, has the ability to implement the type of inspection it deems necessary. Also the frequency of once per calendar year may create some unintended reporting difficulties if Transmission Owners currently track progress and completion of inspections using a differenct convention than calendar year, e.g., fiscal year or other period. It may be helpful to change the wording of R1.2 from "at least once per calendar year" to "once in a twelve month period."
Agree
Agree
BPA agrees with 1.4, with the following change. The ending phrase: "and may include actions such as a temporary reduction in line Rating, switching lines out of service, or other actions" should be eliminated. Not only does BPA feel it is inappropriate to use advisory-type rather than declarative language in a Standard, BPA feels it is also questionable to give examples of imminent response actions that are often not within the direct capability of a vegetation program to enact. Eliminating the reference to these possible actions leaves it up to the Transmission Operator to decide what the eminent threat response is.
Agree
Disagree
BPA opposes removal of Clearance 1. Clearance 1 provides a regulatory justification for a Transmission Owner to apply and extend proactive vegetation threat prevention programs on its rights of way easements across municipal, state, tribal, other federal and private properties. In many cases, without the regulatory leverage of a Clearance 1 requirement, Transmission Owners would be limited to maintaining less effective and higher risk vegetation management practices where it has legal restrictions, then it presently can implement under the present version of FAC 003-01. BPA recommends that Clearance 1 be placed back into the document , but as a Measure and not a Requirement.
Agree
Agree
BPA agrees with R2, but refer to comments submitted regarding R4 (please see our response to Question #15) for related recommendations to R2.
Agree
Agree
Agree
Disagree
R4 states that the Transmission Owner is in violation of the Standard if the Critical Clearance Zone is encroached upon. The CCZ, as defined by the Standard, changes along the transmission line from the

insulator to mid-span, depending on loading, actual operating temperature, wind and ice loading, maximum design rating and operating load, etc. Also, the tandem, Measure M4, requires that the Tramsission Owner has evidence demonstrating that there has been no vegetation encoachments in the CCZ along its transmission system. In order to meet the letter of the Standard, that is to provide evidence that no encroachments in the CCZ have occurred under all manner of these fluid environmental and operating conditions, the Transmission Owner would have to employ the highest level of modeling technology available, which would seem to be LiDAR technology. The standard should not be written in such a manner so that it requires, by all intent and purpose, a Transmission Owner to acquire a particular technology. BPA recommends that the Alternative represented by "the second bullet" above, be used rather than R4 in its present state, or that R.4. be simply dropped and R1.4 modified to state that the imminent threat procedures include immediate removal of encroachments into the Critical Clearance Zone. Also, the term "immediate" implies instantaneous response. The use of another term is recommended, such as "as immediate as human health and safety considerations allow, in order to prevent the possibility of flashover".
Agree
Agree
There is a typographical error / omission in the Technical Reference on Page 36, which states, "R6. Each Transmission Owner shall prevent Sustained Outages of applicable lines due to the blowing together of vegetation and a conductor with (sic) Active Transmission Line Right of Way) operatiing within design blow-out conditions) with the following exception: . . . " I believe the intent is for the statement to read "due to the blowing together of vegetation and a conductor WITHIN Active Transmission Line Right of WAY". This change is needed to make the technical reference consistent with R6. as it appears in the Standard, the definition of Active Transmission Line Right of Way on Page 5 of the Technical Reference, as well as the terminology used on Page 37 in describing Fall-into outages. This needs correction.
Group
Public Service Electric and Gas Company
Jeffrey C. Mueller
Public Service Electric and Gas Company
Disagree
An additional clarifying exception in the footnotes to R4 consisting of a tree that is located off of the transmission owner's right of way falling into the CCZ should be added to the encroachment exceptions. Transmission owners should not be found in violation of the standard for falling vegetation located off of the TO's property.

These comments were prepared by Richard Wolowicz, Manager Vegetation Management, on behalf of Public Service Electric and Gas Company ("PSE&G"). PSE&G also joins with and supports the comments filed by the Edison Electric Institute (EEI) in this matter.
Individual
Ed Davis
Entergy Services
Disagree
Entergy disagrees with changing â€œelectric transmission systemsâ€□ to â€œBulk Electric System.â€□ Historically, the definition of the Bulk Electric System has included all lines operated at voltages 100 kV and greater. The above change in terminology will add ambiguity to which lines this standard is applicable. Entergy is concerned about the potential for this ambiguity leading to the expansion of the applicability of the standard to include lines below 200kv.
Agree
The applicability of this standard should state that it is not applicable to insulated transmission lines, such as underground lines.
Agree
Agree
Agree
Agree
Disagree
1. The requirement should state that each Transmission Owner will be responsible for creating and maintaining a Vegetation Imminent Threat Process. This process will clearly define how the Transmission Owner defines a vegetation imminent threat. 2. The requirement needs to state that only vegetation conditions identified, to the Transmission Owner, by regular field inspections, including aerial inspections, and other internal and external verifiable reports of vegetation imminent threats will be managed through this process. 3. If the standard requires a process to mitigate potential immediate threats to the system, the term â€œvegetation imminent threatâ€□ must be defined. This definition must not delineate the precise steps that are required to be taken to allow experts as many options as necessary to address each vegetation condition specifically. 4. The list of possible mitigating actions should be removed from the standard since it is not an all inclusive list. Listing these actions in the standard may imply that the entity must do one or all of the actions to be in compliance. The entity must have sufficient latitude to evaluate each possible vegetation condition and apply the most appropriate mitigation steps, up to and including the removal of the identified vegetation.
Agree
Agree
Agree
Disagree
: 1. Entergy suggests that the requirement for activation of the vegetation imminent threat process should not be tied to the Critical Clearance Zone and that the each entity should define the activation of their vegetation imminent threat process. Tying the activation of the imminent threat process to the Critical Clearance Zone is limited in that this criterion does not address the possibilities of vegetation falling into the line or Critical Clearance Zone. 2. In the sentence â€œCritical Clearance Zone approached by vegetationâ€□ â€“ the use of â€œapproachedâ€□ is subjective and not specifically quantifiable. Effective, uniform activation of the imminent threat process will require objective measurement criteria. 3. The standard needs to include a clear statement to the effect that

when the Transmission Operator is notified of a potential vegetation problem, obtained by normal operations and inspections, the entity will activate the Vegetation Imminent Threat Process. 4) This requirement, as stated, is redundant. The requirements for maintaining the Critical Clearance Zones and / or avoiding vegetation outages, and the associated Violation Risk Factors and Violation Severity Levels, already reinforce the desired behavior of the entity to identify and mitigate any potential issues before the possibility of vegetation causing an outage.
Agree
Agree
Agree
Disagree
1. Entergy believes that outages caused by vegetation are the most reasonable and objective measures for a violation which is not consistent with the proposed R4. See additional comments in section 16 related to R5, 6, and 7. 2. If R4 remains, Entergy proposes that the most reasonable approach to this requirement is a variation of the second bulleted option. This variation would include wording clarifying that only known encroachments of the Critical Clearance Zone would be considered violations. Entergy is willing to include failures to enact the imminent threat process (which is really a violation of R2) and also known vegetation inside the Critical Clearance Zone. This variation should continue to include the exceptions for natural disaster and human activities. 3. Determining objective, quantifiable encroachments into the Critical Clearance Zone is very challenging in field operations because such determination may require a degree of accuracy only obtainable using survey equipment or other sophisticated, costly measuring devices. 4. Entergy is concerned about the challenges of uniform auditability due to noted uncertainties and the statement of absolute criteria that have to be shown in the negative. If the first bullet option is approved for R4, Entergy suggests the sentence â€œEvidence will be required to prove that no encroachments of the Critical Clearance Zone have occurred anywhere at the any time during the annual compliance periodâ€□ be deleted. It is very difficult in regulatory terms to attest that no vegetation has ever crossed the Critical Clearance Zone during the time period being reviewed given the wide range of potential conditions that may not have been detected or even been detectable unless the conditions afforded direct observation. Too many assumptions would have to be made for an entity to self certify to this requirement. If R4 is implemented as stated, those assumptions need to be stated and clarified. 5. If any version of R4 is approved, Entergy suggests that the standard include an exception for trees falling from off the right of way and encroaching the Critical Clearance Zone. For example, a tree that falls from off the right of way. During the fall towards the conductor, the tree could possibly break the Critical Clearance Zone without causing an outage or even a threat of an outage yet still be a violation of the proposed standard. 6. If the second bulleted item is approved, it should be altered to read â€œa violation would have occurred only if no vegetation imminent threat process was initiated.â€□ 7. Entergy does not feel the third bulleted item is adequately defined to use as a requirement in the standard at this time. 8. Conditions for blow-out, in the development of the Critical Clearance Zone, need to be defined in the standard. Their inclusions, in the white paper only, are not appropriate, as well.
Disagree
1. If a version of R4 that states an encroachment to the Critical Clearance Zone is a violation, Entergy disagrees with the need for R5, R6, and R7 because it is redundant to R4. An outage cause by vegetation: a) growing into the line b) blowing into the line and c) falling into the conductor would require the vegetation to break the Critical Clearance Zone. If these requirements stay in the standard, an outage of the above nature would mean the entity violated two requirements, R4 and R5, R6, or R7. 2. Entergy is amenable to keeping R5, 6, and 7 if R4 is removed from the standard. 3. If approved, we suggest that R5, 6, and 7 not apply to trees from off the right of way.
Agree
Entergy would like to note that requirements R1.3 and R8 are administrative requirements that add marginal value to the reliability of the Transmission System. Since entities are required to have flexible annual plans, deviations from the annual plan only need to be documented and these requirements will be met. Entergy utilizes annual plans as a good practice but sees limited value with the inclusion in this standard.

Entergy requests that the proposed FAC-003-2 revision continue work on clarifying the above mentioned â€œDisagreeâ€☐ items and appreciates the consideration of the above comments in the development of the standard. A clear understanding of all standard requirements by the industry is needed to make certain field implementation is achieved and that ultimately we improve system reliability.
Individual
Anita Lee
Alberta Electric System Operator
Disagree
The AESO believes that the inspection schedule should consider local and environmental factors that may impact the anticipated growth rate of vegetation. In many of the areas in Alberta, due to cold climate and arid conditions, we have slow vegetation growth rates. The requirement for minimum annual inspection is not necessary. We recommend the inspection schedule be determined by the Tranmisssion Owner and documented in its vegetation management plan.
The AESO is also a signatory to the joint ISO/RTO Council Standards Review Committee comments which reflect our comments to the other questions in the Comment Form.
Group
FirstEnergy
Sam Ciccone
FirstEnergy Corp.
Agree
Agree
Agree
The Inactive Right of Way, by definition, should include a strip of trees on each side of the of the right of way that was purchased, but not cleared at the time of construction. This could be a narrow strip ten feet on each side that is intended for future hazard tree removal.
Agree
Agree
Agree
Although we agree with R1.3, we suggest it be broken up into subrequirements to allow for better

clarity to the reader as well as aid in the development of violation severity levels when developed. We suggest the following: R1.3. Require an annual plan that includes the following as a minimum: (Note: Adjustments to the plan within the year are permissible) R1.3.1. It shall identify the applicable lines to be maintained and associated work to be performed during the year. R1.3.2. Is shall be flexible to adjust to changing conditions and to findings from vegetation inspections. R1.3.3. It shall take into consideration permitting and scheduling requirements from landowners or regulatory authorities. R1.3.4. It shall support the objectives of the transmission vegetation management program and use the methodologies outlined in the transmission vegetation management program.
Agree
The safety of the personnel required to remove a tree or vegetation on or near an energized conductor must be considered when implementing the imminent threat procedure. Although this is a reliability standard, the safety of the personnel may be one "trigger" to implement the imminent threat procedure. That being said, the workers on site, in their judgement, are not able to remove the vegetation safely then the imminent threat procedure would be implemented. See comments for CCZ.
Agree
We agree with the concept of a corrective action plan. However, it is not clear what flexibility the TO is afforded in making adjustments to the work plan that may carry over from one calender year to the next. Legal issues with property owners or other factors may prevent the utility from carrying out the work plan as scheduled. Also, we question the use of the term "constrained". It should be clear as to what constitutes appropriate or valid constraints.
Agree
Agree
Disagree
The CCZ is not equal to Clearance 2 in FAC-003-1. Per requirement R4, any encroachment into the CCZ is a violation of the standard even if an outage does not occur. This is too strict because it refers to a "0" tolerance even for encroachments that do not affect reliability. This can be an extremely costly standard to comply with that may or may not improve reliability. The CCZ distance is a difficult to determine from one moment to the next based upon the description and calculations outlined. The conditions on the right of way are dynamic and ever changing. It would be more proactive for the TO to focus on implementing the TVMP rather than expending time and money trying to determine if the CCZ has been violated. A better approach would be to establish a minimum clearance at all times rather than to monitor encroachment to a theoretical CCZ.
Agree
Agree
Agree
Disagree
Providing evidence to prove that there were no encroachments of the CCZ is difficult at best. An occurrence of an encroachment does not necessarily translate to an outage. The CCZ is dynamic and difficult to measure exactly from span to span and day to day and is dependent on environmental and line conditions. The costs to comply with this requirement as written are difficult to justify considering that reliability may not be improved at all. FirstEnergy believes that the first alternative above should be used and is a more logical approach from both a reliability and compliance standpoint. Furthermore, since the first alternative is already covered by the currently proposed wording of R2, the only changes needed to the standard are to remove the proposed R4 and M4 and re-number the requirements.
Agree
Agree

FirstEnergy agrees with the intent of R8, but the standard should be clarified by removal of the word "easement". As written the standard is open to interpretation between "easement" and active right of way. It is important to have the term "legal rights" remain in the standard. The TO should be held accountable to fully enforce the legal rights outlined in maintaining the active right of way. This will lead to a more reliable transmission system.
FE provides these additional comments for consideration: 1. Regarding the Applicable Facilities - Section 4.2.2 would be more appropriately placed under Sec. 5 "Effective Dates" since it deals with the timeframe the TO has to implement its TVMP on sub-200 kV lines. - Section 4.2.3 - We suggest removing this section. First energy does not agree that this standard should dictate the amount of time a TO has to obtain compliance with this standard for newly acquired transmission lines. It should be the responsibility of every organization to "self-report" its compliance issues and planned mitigation plans for all standards when they acquire new lines or facilities. If the SDT believes this should be explicitly stated, then it should recommend to NERC that explicit language be placed in the NERC Rules of Procedure. No other standards set timetables for newly acquired facilities and this standard should be no exception. 2. Regarding R1.1, this subrequirement requires the TO to specify the methodologies it uses to control vegetation. It should be clear that not all of these methodologies are required to be deployed in every situation (as explained in the white paper pg.12). We suggest rewording the requirement as follows: "R1.1. Specify the methodologies that the Transmission Owner may use to control vegetation." 3. R1.5 requires a process for "interim corrective action" be specified in the TVMP. However, the standard does not explicitly specify that this corrective action be implemented when the TO is constrained from performing vegetation maintenance as planned. 4. As written, in addition to the responsible RC, R9 may imply that this requirement is also the responsibility of the TO(s) and neighboring RC(s) due to the use of the term "jointly". Also, R9 should require the RC submit the list of designated lines below 200 kV to the TO(s) and neighboring RC(s) within a reasonable time-frame after its completion. We suggest rewording and addition of subrequirements to R9 as follows: R9. Each Reliability Coordinator, in consultation with its Transmission Owner(s) and neighboring Reliability Coordinator(s), shall prepare and keep current a list of designated applicable lines that are operated below 200kV, if any, which are subject to this standard. R9.1. The RC shall submit the list to the impacted TO(s) within 30 calendar days of completion and/or revision. R9.2. The RC shall submit the list to its neighboring RC(s) within 30 calendar days of completion and/or revision. Lastly, measure M9 will need to add sub-measures for the proposed additions above. 5. Requirement R10 should require that the RC ONLY uses the assumptions detailed in R10.1 and R10.2 to designate a line as significant. Also, R10.1. should reference the IROL methodology standard FAC-011 since it directly ties into this requirement. Also, in R10.2, "grid" should be replaced with "BES" and the term "failures" is not necessary. We suggest re-wording R10, R10.1 and R10.2 as follows: R10. Each Reliability Coordinator shall document its method for assessing the reliability significance of sub-200kV lines and shall be based only on the following: R10.1 Transmission lines whose loss would result in the exceedance of an Interconnection Reliability Operating Limit (IROL) as determined by standard FAC-011. R10.2 Transmission lines whose loss would place the BES at an unacceptable risk of instability, separation, or cascading.
Individual
Richard Kafka
Pepco Holdings, Inc
Agree
Agree
FERC Order 693 essentially has the RC replacing the RRO.
Agree
Agree
Disagree
While an annual inspection is reasonable and appropriate for all but very low precipitation areas, In Order 693, the Commission directs the ERO to develop compliance audit procedures, using relevant industry experts, which would identify appropriate inspection cycles based on local factors. The SDT

does not seem to have thaken the local factors into account. FERC also does not want to leave this up to the Transmission Owners. While the standards being developed are moving many things to the RC, PHI sees that as the only way to have someone other than the TO determine an inspection cycle that would consider local factors.
Agree
Disagree
While an imminent threat procedure is prudent and reasonable, it does not need to consider a Critical Clearance Zone as addressed in our comments on other questions. In fact, one can quickly provide examples of imminent threats when the threat is not even on the right of way. The TO should simply have an imminent threat procedure to address identified imminent or potential imminent threats.
Agree
Agree
Agree
Disagree
R5, R6 and R7 make this requirement redundant and unnecessary - it should be deleted. It is largely unenforceable and does not make the standard clear, specific and regulatorily enforceable. Further, PHI believes the concept of enforcing no encroachment into the Critical Clearance Zone is a flawed approach.
Agree
Agree
Agree
Disagree
As discussed in our response to Q11, the concept of encroachment into the Critical Clearance Zone is flawed. It is enforceable almost exclusively through self reports. R5, R6 and R7 provide all incentives for the TO to follow its inspection and maintenance plans, and R2, if properly written to remove references to the Critical Clearance Zone provides additional incentives. R4 is not needed and should be deleted. PHI is puzzled where this concept came from. Nowhere in Order 693 is this concept discussed.
Agree
There is no need for three separate requirements if the incident is a Sustained Outage, but there is nothing inherently wrong with the three requirements.
Disagree
THE SDT has introduced the term Active Transmission Line Right of Way. R8 should use this term to avoid any misinterpretation.
Individual
Virginia Cook and Kim Wheeler
JEA
Disagree
We disagree with this change as it may cause confusion on the applicability of the standard as the BES is generally 100kV and above, but this standard generally applies to 200kV and above.
Agree
Disagree

The standard should EITHER require an entity to have and follow a program OR hold an entity to performance standards, but not both. Requiring a procedure in conjunction with performance requirements incents the entity to write procedures that meet only the minimum requirements of the standard, as they will be audited and held accountable for what is documented and performance against that. If performance requirements are in place without the concurrent requirement for a procedure, then the entity is incented to develop procedures that meet best practices in order to assure that they will meet or beat the performance standards, because in this scenario, such procedures do not expose the entity to additional compliance risk while enhancing reliability.
Disagree
See comment from #3.
Agree
Although there are probably few areas where this is appropriate, the entity should be able to reduce the required number of inspections with RC approval if they are able to demonstrate that vegetation conditions surrounding transmission lines does not warrant inspections at that frequency.
Disagree
See comment from #3.
Agree
It is appropriate to require procedures to respond to "emergency" condidtions, however Imminent Vegetation Threat should be a defined term.
Agree
Agree
Agree
Disagree
The use of Gallet equations is not practical either for field use or for demonstrating compliance.
Agree
Agree
Disagree
See comment from #3.
Disagree
As written, demonstration of compliance may not be feasible and would certainly be prohibitively expensive, consuming resources better spent managing vegetation. In general, putting entities in the position of proving something didn't occur is exptremely difficult and burdensome, without really aiding reliability. If the incident was significant, the region would know about it, and investigations can be pursued, if warranted. The first alternative requiring implementation of the imminent threat procedure is a better choice.
Agree
Disagree
See comment from #3.
M5, 6 and 7 ask the entity to prove the negative. This type of evidence is problematic, and may result in nothing better than the entity making an attestation that the event did not occur, thus this measure is not useful. With well over 100,000 miles of transmission covered by this standard, even six-sigma performance would result in vegetation related issues. It is unreasonable to expect zero-tolerance for vegetation events and unneccessary for the industry (and customers) to expend resources to attempt to meet this level of compliance when the transmission system is planned and operated to handle any single contingency, which means that a vegetation contact should not, in isolation, cause a major problem to the bulk power system. This standard needs work to make it

clear, unambiguous, feasible and enforceable.
Individual
Dan Rochester
Independent Electricity System Operator
Agree
Disagree
The IESO does not see a role for an RC or PC in a vegetation management standard. All TOs need to ensure they have a vegetation program to avoid unnecessary tripping of transmission lines, particularly those that impact the BES. We are of the view that identification of critical facilities is not a part of this standard; it belongs to other standards that deal with SOL/IROL calculations, SPS, protection and critical infrastructure protection. R9 and R10 should therefore be removed from the standard.
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
Agree
We recommend removing the Transmission Owner as the one to define a major storm, this task should be left to an applicable regulatory body only, for consistency in assessing such an event. Also, we recommend footnote #5 specify that planned removal of vegetation by the utility is not part of the exceptions, because in our view this activity is a component of the vegetation management program and that outages should be preventable. There is a typo in R6. The numeral "4" should be superscripted.
Individual
Karen Powell
Salt River Project
Agree

Agree
Disagree
R1.1 states "Specify the methodologies that the Transmission Owner uses to control vegtation". The word "methodologies" does not adequately replace "objectives, practices, approved procedures, and work specifications". Recommend to keep the original wording.
Disagree
Although we agree that it is important to identify both aspects of the program for "prepare/documentation" and "implementation", we do not agree that this needs to be documented in separate requirements. It makes the standard longer than necessary and creates redundancy. The document would be easier to follow if the two elements were kept together in the same requirement. In addition, it is not defined what is "VRFs". We understand that this was detailed in a previous draft document as "Violation Risk Factor". This needs to be defined and clarified in order to provide comment back.
Agree
The Transmission owner needs the ability to define what an inspection is in the context of their utility operation. Inspections may not constitute a dedicated, comprehensive vegetation management inspection, but could often be part of a routine line patrol, where linemen or engineers look for vegetation concerns in addition to undertaking maintenance work. Clarification of that would be helpful, suggest that could be documented in the Technical Reference document.
Disagree
The document would be easier to follow if the two elements were kept together in the same requirement (similar to comments stated in Comment #4 above). It makes the standard longer than necessary and creates redundancy. Also, under the new wording in R1, the TVMP no longer has a requirement to include objectives. However, there is a phrase in R1.3 to "support the objectivesâ€¦and methodologiesâ€¦outlined in the...program". To be consistent with R1.3, it is recommended that R1.1 be reworded to specify the methodologies and objectives that the Transmission Owner uses to control vegetation.
Disagree
Agree with R1.4, however with the suggested change: Remove the language "â€¦and may include actions such as a temporary reduction in line Rating, switching lines out of service, or other actions.". Any stardard should not contain advisory-type language, it should be declarative in tone. The suggested actions are not the responsibility of the vegetation management program.
Agree
Disagree
Recommend adding it back to the document, however, only if it is changed to become a measurement (M) rather than a requirement (R). Leaving it in as a measurement provides justification and leverage for operational clearances when dealing with landowners. Without Clearance 1 landowners may only allow vegetation clearance just at the Critical Clearance Zone at all times, which is not a feasible, cost-effective, or responsible way for utilities to manage vegetation clearance.
Agree
Agree
Although we agree that using the Gallet equation is more definitive than using IEEE 516, we still question from an engineering prespective as to how and why this method was chosen. It is stated in the Technical Reference paper that the Gallet Equation is a well known method of computing the required strike distance for proper insulation coordination. It is our understanding it's purpose is for designing towers, to define the "tower window" or opening inside of a tower under normal conditions. Because this is not a method designed specifically for vegetation management, was there any physical testing involved in choosing this approach, such as testing in both wet and dry conditions? We would recommend additional information to clarify this method to use for vegetation management. See additional comments in Comment #18 below. In addition, we feel this clause makes R4 redundant, as per our comments under Comment #15 below.

Agree
As commented in Comment #11 above, although we agree that using the Gallet equation is more definitive than using IEEE 516, we still question from an engineering prespective as to how and why this method was chosen. It is stated in the Technical Reference paper that the Gallet Equation is a well known method of computing the required strike distance for proper insulation coordination. It is our understanding it's purpose is for designing towers, to define the "tower window" or opening inside of a tower under normal conditions. Because this is not a method design specifically for vegetation management, was there any physical testing involved in choosing this approach, such as testing in both wet and dry conditions? We would recommend additional information to clarify this method to use for vegetation management. See additional comments in Comment #18 below.
Agree
As commented in Comments #11 & #12 above, although we agree that using the Gallet equation is more definitive than using IEEE 516, we still question from an engineering prespective as to how and why this method was chosen. It is stated in the Technical Reference paper that the Gallet Equation is a well known method of computing the required strike distance for proper insulation coordination. It is our understanding it's purpose is for designing towers, to define the "tower window" or opening inside of a tower under normal conditions. Because this is not a method design specifically for vegetation management, was there any physical testing involved in choosing this approach, such as testing in both wet and dry conditions? We would recommend additional information to clarify this method to use for vegetation management. See additional comments in Comment #18 below.
Disagree
The document would be easier to follow if the two elements would be kept together in the same requirement (similar to comments stated in Comments #4 & #6 above). It makes the standard longer than necessary and creates redundancy.
Disagree
Disagree with R4 as it is written. The new requirement in R4 stipulates that the Transmission Owner is in violation if an encroachment of the Critical Clearance Zone occurs at any time. However, the Critical Clearance Zone changes with each foot of the transmission line from the insulator to the mid-span, depending on loading, actual operating temperature, wind loading, ice loading, maximum design rating, maximum operating load, and so on. See additional comments in Comment #18 below. Furthermore, Measure M4 requires that the Transmission Owner has evidence demonstrating there were no vegetation encroachments into the Critical Clearance Zone. To provide evidence demonstrating there were no vegetation encroachments into the Critical Clearance Zone would be an extremely onerous task and an expensive requirement for the utilities. We strongly support changing this to the 1st alternative written in Comment #15 "One alternative to R4 required immediate removal of the vegetation or immediate implementation of the immenent threat procedure upon discovery of a possible encroachment of the Critical Clearance Zone, thereby proactively preventing an outage. A violation would have occurred only if the immenent threat process was not successfully implemented." This alternative is essentially the same as R2, therefore, we recommend removing R4 from the standard entirely.
Disagree
Recommend that the requirement under R7 be changed from "shall prevent sustained outages" to "shall minimize sustained outages due to vegetation falling into a conductor". We understand that the word "minimize" was present in earlier drafts of the document. We are concerned about the requirement to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. This could lead to an incident where a utility is charged unreasonably - for example, for an outage from a tree that was one foot within the active ROW line. We should not be held liable when reasonable due diligence is practiced. Furthermore, it is not economically feasible for utilities to survey every ROW to determine precise clearance zones.
Disagree
The document would be easier to follow if the two elements would be kept together in the same requirement (similar to comments in #4, #6, & #14 above). It makes the standard longer than necessary and creates redundancy.
We question the method used in determining the clearance distances for Vegetation near Transmission Lines. First is the use of the Gallet Equation. Although the Gallet Equation is more

definitive than using IEEE 516 as identified in the current standard, we have questions from an engineering prespective as to how and why this method was chosen for vegetation management. It is stated in the Technical Reference paper that the Gallet Equation is a well known method of computing the required strike distance for proper insulation coordination. It is our understanding it's purpose is for designing towers, to define the "tower window" or opening inside of a tower under normal conditions. Because this is not a method designed specifically for vegetation management, what is the basis for applying this to vegetation management? Was there, or could there be testing done? We would find it definitive to substantiate the calculated equation assertions with test data from actual energized flashover distances to vegetation. The testing ought to include dry and misting conditions at 200+ kilovolt levels on a sampling of fresh cut common vegetation types. Reputable EHV testing facilities where such tests can be performed exist within the United States and Canada. Is there additional information to clarify why this method was used to help establish clearance distances for vegetation near transmission lines? Second, it is expected that each utility needs to define their "Critical Clearance Zone". It is outlined in the Technical Reference document how complicated it is to define this clearance area. As the conductor moves throughout its "flight path", the minimum clearance shell surrounding the conductor moves along with it. The shape and size of the Critical Clearance Zone around the conductors is irregular and will change depending on where a conductor segment is located within the span. At mid-span, where the potential for conductor movement is the greatest due to sag and wind deflection, the corresponding Critical Clearance Zone is also the largest and most irregular. With the size, shape, and area of the Critical Clearance Zone dramatically changing as one progresses along a span, identifying the precise location and boundary of the Critical Clearance Zone around the conductor in the field becomes very problematic. There are many variables that are involved at any point along a line and at any given time (loading, operating temperature, wind, maximum design rating, maximum operating loading and so on). Therefore, even if the exact size and shape of the Critical Clearance Zone is known, it becomes nearly impossible to field correlate and accurately "superimpose" the Critical Clearance Zone" around the conductor. Therefore, it seems unreasonable to expect each utility to develop and implement a defensible and auditable clearance zone. We strongly support the development of the Technical Reference document. This would have been helpful if it was available for the first version, as it will help both utilities and auditors. We recommend that this be included in the revised version and subsequent future revisions. Please note that as FAC-003-2 goes through additionals revisions prior to finalization, the Technical Reference document needs to be revised to reflect the final revisions prior to implementation.
Individual
Rick White
Northeast Utilities
Agree
Agree with the term "bulk electric system." Disagree with the wording of the Purpose Statement; The Purpose statement reads "To improve the reliability of the bulk electric system by preventing vegetation related outages that could lead to Cascading." One vegetation-caused outage does not in and of itself cause Cascading. Cascading will only result due to a combination of events - either multiple vegetation outages during the same time or an outage coupled with equipment malfunction or operational errors. The document seems to be internally inconsistent in this regard. The Techincal Reference for FAC-003-2 notes that outages due to trees falling from outside the right-of-way or other outage causes on a critical facility would not constitute a possible cascading effect. If one occurance of these types of outages would not constitute a cascading potential then one must wonder why an outage from a tree contact within the right-of-way is considered a possible cascading event? Suggest rewording the statement to exclude the comment about Cascading and use "by preventing vegetation related outages on critical transmission facilities."
Agree
One question: Will the Reliability Coordinators use consistent criteria for listing sub 200-kV facilities to be included under FAC-003-2? The purpose of FAC-003 is to ensure inter-regional reliability and to focus on the reliable operation of these lines. By leaving the decision up to the individual Reliability Coordinators - there is the potential for local differences in determining which sub-200-kV facilities may be critical. This could result in some transmission owners having to include certain facilities under the requirements of FAC-003-2 where in other regions of the country - similar facilities may not be included by the Reliability Coordinator. Although there have been criteria established to guide the Reliability Coordinators in the detemination of sub-200-KV facilities for inclusion under FAC-003-2 - is

this sufficient to ensure uniformity throughout the US? Perhaps some involvement at the Regional Entity level at least, is warranted.
Agree
With respect to "active transmisison line ROW" the examples provided in the Technical Reference document for FAC-003-2 show that any areas of the easement or fee-owned right-of-way not cleared in accordance with company approved design standards will not be considered "active transmission line ROW". Any vegetation contacts resulting from trees that fail in these non-cleared sections ("corridor edge zones") would not constitute a violation of FAC-003-2. The definition of the "active transmission line right-of-way" states that this does not include areas of the easement or fee-owned property that is unused or inactive and intended for other facilities. Does this imply that areas not cleared and not intended for other facilities are part of the active right-of-way? If a company had constructed new lines and allowed for a buffer strip of the easement that was not cleared, but is also not intended for new facilities, and trees are allowed to remain in this strip - that an outage from contact with a tree falling into the lines from this buffer would constitute a violation of R7 as a tree falling from within the active right-of-way? Does this imply that trees in these buffer strips must be removed? This will constitute a very costly and problematic position that will result in extreme adverse public opposition to the required clearing. It is suggested that the clearing limits of any right-way comply with some established standards or codes. A utility should not be allowed to eliminate a large number of vegetation violations by simply decreasing the size or width of the active right-of-way. However, this may also need to be flexible when new lines are constructed when easement widths are limited due to local or state requirements.
Agree
Agree
Agree
Disagree
Agree with the need to have and implement when necessary an imminent threat procedure. Disagree with the need to implement the imminent threat procedure merely because a CCZ is being approached, as required by R2. Is there a desired distance from the CCZ where this procedure must be implemented, since all vegetation within a right-of-way will "approach" the CCZ as it grows? How will time of year and operating conditions be factored in, which may change the requirements to perform control during periods of low temperature or low load? It would not be necessary to perform all the requirements of an imminent threat procedure when there is adequate clearance to schedule the work without jeopardizing the reliability of the system. For example, in mid winter a line is 8 feet from a tree - there is little chance of the line reacing maximum sag at that time of year and the present condition does not constitute an imminent threat at that time. Also, disagree with the requirement for the imminent threat procedure to include actions that could be taken by the TOP (reduction in line rating, switching). The requirement should be limited to notifications to the TOP, since decisions on what specific system operating actions to take are beyond the responsibility of the TO. The decision on what actions to take needs to be performed either by the TOP, or by the TOP in conjunction with the TO.
Agree
Agree
Agree
Agree
Agree
Agree

Agree
Disagree
First - the determination of the CCZ is highly problematic in the field. Second - it is impossible for any utility to certify that no encroachments have occurred at any time unless a utility has completely removed all potentially interferring vegetation on all areas of their transmission system. If the standard is to clearcut and maintain a tree free right of way, the standard should say so. To determine if vegetation may have violated the CCZ the inspector must know at the time of the inspection the ambient temperature, the wind speed, the loading of the line and the actual distances between the vegetation and conductors. Then, the information must be compared to possible extreme operating levels of the line under all conditions to know if the vegetation may violate the CCZ. As stated - it is improbable that this could accurately be performed in the field as the data changes within each segment of a span's length. The first alternative provides the most effective means of addressing encroachment of the CCZ - having an encroachment is not a violation - knowing there is an encroachment and not correcting the problem would be a violation. Implementing the imminent threat procedure and correcting the problem is a more effective approach. Having a zero tolerance for encroachments of the CCZ under all situations and operating conditions would sub-optimize the use of resources. No actual event may have occurred on the system, yet the utilities will be in violation just for a possible or potential problem that even under extreme operating conditions may not actually occur. It would be best if the violations were limited to "known encroachments" (not "possible encroachments") such as would occur if a line were to trip due to vegetation contact, or if there is evidence of any burns. If no action was taken on known encroachments to correct the problem (such as implementation of the imminent threat procedure) then a violation will have occurred. It is doubtful that any utility will be able to certify that at no time has vegetation encroached into the CCZ. Utilities will have to spend an untold amount of resources to verify that there have not been any encroachments during a compliance period - instead of using these resources more effectively in taking proactive measures to manage and control encroaching vegetation. As written, any encroachment into the CCZ is considered a violation of FAC-003-2 (R4). There are exceptions provided for encroachments due to natural disasters and human or animal activity. There is no exception for encroachments due to the failure of a tree(s) outside of the active transmission line ROW. Based on R4, a trip and reclose of a transmission line (no outage) is a violation even if the tree is outside of the active right-of-way; whereas per R6 and R7, a line outage would not be a violation if the tree was outside of the active right-of-way. As written - this is not clear - there should be exceptions to allow for trees falling into the CCZ (and into the active transmission line right-of-way) from outside the limits of the active transmission line right-of-way. Also - how are violations of the CCZ requirement to be reported - there is no provision for the reporting process and requirements (specifics on the type of violation). Will this be addressed in the Compliance Section yet to be added?
Agree
Agree that contacts resulting in sustained outages due to vegetation from within the active transmission line right-of-way should constitute a violation of the Standard. However, this Standard is written for a zero tolerance of any vegetation caused outages or encroachment into the CCZ. One vegetation-caused outage or one CCZ encroachment may not result in a potential Cascading effect. Agree with the use of different violation risk factors (VRF's) and violation severity levels (VSL's) for each of the three outage classes. Also - how are outage violations to be reported - there is no provision in the revision for the reporting process and requirements (specifics on the type of violation). Will this be addressed in the Compliance Section yet to be added? Suggest in both R6 and R7, move the phrase "within an Active Transmission Line Right of Way" to immediately follow "vegetation".
Agree
In section 4.2.2. the time period for bringing sub 200-kV lines into compliance with the standard states a 12 month period following the designation of the lower voltage lines by the Reliability Coordinator. This can present problems if the RC designates the lines during the course of a plan year, because budgets may not have been established or funded for the additional work. It is suggested that the time period be revised to state, "by the end of the following calendar or budget

year after the designation of lower voltage lines", allowing for a full calendar/budget year that can be planned and budgeted to bring lines into compliance. There is concern over the use of the CCZ and making this the "bright line" where encroachment at any time under any conditions is a violation of the standard. The CCZ is a very detailed and calculated zone. It is improbable that an accurate determination of the CCZ could be made in the field. Mere encroachment should not constitute a violation. If the encorachment can be determined and corrected once found - this should be an acceptable practice. It is reasonable for utilities to spend the time, money and manpower to actively manage rights-of-way, and dealing with encroachment issues which can be identified. Many potential encroachments will not be identifiable unless one can accurately identify the CCZ in all cases in all areas at all times. Also, there is some concern over how the requirements are set up for violations of the CCZ and for sustained outages. A sustained outage due to vegetation within the active transmission right-of-way is a violation under R.5, R.6 and R.7. It is also possible that the outage is a violation of the CCZ under R.4. The standard implies that a utility could be assessed multiple violations of the standard for one outage with multiple penalties. Is this the desired intent? Finally, version 1 had clear requirements on what was to be reported, when the reports were required, and who was to submit reports. Is it intended that the standard rely soley on self-reports? Version 2 makes no mention of what is to be reported when a violation occurs, or of any other reports. Is reporting going to be left up to the Regional Entity to establish?
Individual
Roger Champagne
Hydro-Québec TransÉnergie (HQT)
Agree
Disagree
HQT believe that the Planning Coordinator (PC) should be the entity responsible to determine the elements part of the BPS submitted to this Standard, and in fact for all other Standards. Those elements should be determined by an impact based methodology, as used in NPCC, with no voltage limitation and no fixed voltage treshold level as imposed in Applicability 4.2.
Disagree
While we agree with the suggested changes for the terms proposed , we believe that the TVMP should be focused on removal of incompatible vegetation from the Active Right of Way. R1.1 could read:Specify the methodologies that the Transmission Owner uses to control vegetation and demonstrate that the removal of non-compatible vegetation is a focus within the plan. Incompatible vegetation should be defined as any vegetation which has the potential to grow tall enough to jeopardize the integrity of an applicable transmission line by growing into the CCZ or falling into the CCZ. This would provide clear guidance to all stakeholders, support long term vegetation management philosophies, and complement methods such as IVM where incompatible vegetation is completely removed, and compatible vegetation is encouraged to proliferate, thereby helping to control incompatible vegetation in an environmentally positive manner.
Agree
Disagree
The frequency and need for inspection is based on a number of factors that include: type of vegetation on a right of way, rainfall during any given year, climate (very slow growth in nordic area), when the last removal of vegetation was done, etc. HQT believes R1.2 is overly prescriptive when a «at least once a year» becomes mandatory; these terms should be removed from the Standard.
Disagree
R1.2 and R1.3 specify calendar year. The individual entities should define the 12 month period for their programs.
Disagree
While we strongly agree that an imminent threat procedure should be required in the TVMP, we disagree with some specific wording in R1.4. R1.4 requires immediate communication of an imminent threat to the Transmission Operator, which we would normally agree with. R2 however requires that the imminent threat procedure be implemented when the Critical Clearance Zone (CCZ) is approached

by vegetation. "Approached" is not defined as a specific distance, so this part of the requirement is left up to the individual's interpretation. In cases where the CCZ is approached by vegetation no threat to the system is possible if the vegetation is removed before it actually grows into the CCZ. In many cases the vegetation can be removed without taking clearance outages because the CCZ is large, and the conductor and vegetation are still relatively far apart. In such cases there is no need to notify the Transmission Operator, although there is a need to remove the vegetation immediately. We recognize that the opposite is also true, and that in some cases it will be necessary to notify the Transmission Operator because a clearance outage or line de-rating may be required to remove the vegetation. We therefore suggest a simple change to the wording of the second sentence of R1.4. Change "â€¦. specify actions which shall include immediate communication of the threat to the Transmission Operator, and may include actions such as a temporary reduction in line Rating, switching lines out of service, or other actions" to "... specify actions which may include immediate communication of the threat to the Transmission Operator, a temporary reduction in line Rating, switching lines out of service, or other actions". This change will address the issue which is described above and will allow each Transmission Operator to develop an imminent threat procedure that best fits their system. It should also be noted that many Transmission Operators have imminent threat procedures in place to address all imminent threats to their transmission system, not just threats due to vegetation. It makes sense for Transmission Owners to have only one imminent threat process, therefore the flexibility that can be achieved in the context of this standard would be helpful.
Agree
Agree
We agree but believe that the TVMP should target removal of all incompatible vegetation on the Active Right of Way as described in the response to question 3.
Agree
Agree
Agree
Agree
Agree
Disagree
The purpose of the standard is "To improve the reliability of the Bulk Electric System by preventing vegetation related outages that could lead to Cascading". We believe that R4 is not the most effective way to achieve this purpose because it does not provide incentive for Transmission Owners to take advantage of modern technology, such as aerial laser survey (ALS) using Light Detection and Ranging technology (LIDAR), that is capable of accurately identifying vegetation which is approaching the CCZ or has encroached into it. In fact R4 provides an incentive not to utilize this technology because Transmission Owners who identify encroachments would be in violation of R4 for each identified encroachment. On the other hand, Transmission Owners who choose to be less proactive often would not identify such encroachments because the CCZ and encroachments of it are generally not easy to determine without taking precise measurements. Unless the line is heavily loaded or the vegetation is significantly overgrown, encroachments of the CCZ would not be readily noticed. In most cases these Transmission Owners would simply remove or cut back incompatible vegetation without taking measurements. The threat to the line would have been eliminated with no encroachment having been identified. R4 presents a dilemma for Transmission Owners that are considering making the significant investment in ALS technology. While the technology would allow them to identify any potential grow-in or fall-in conditions, it would also expose them to the risk of identifying violations of R4, that would otherwise not have been identified. Violation Risk Factors (VRFs), Violation Severity Levels (VSLs), and Time Horizons are not included in this Draft, but after making a significant investment in ALS, Transmission Owners could be faced with significant additional cost in terms of NERC penalties. In addition, even if the penalties were relatively low they would be exposing themselves to violations

that less proactive Transmission Owners would not be exposed to. In our view R4 as written would, in some cases, have the opposite effect of what is intended because the business case for using ALS is more difficult to make. This will result in less use of ALS and other emerging technology that is likely to be developed. This would result in fewer problems being identified, a small percentage of which will not be discovered until they result in a line trip. Still we believe that the concept of the CCZ is a good one and recommend that R4 be changed so that Transmission Owners are provided with an incentive to invest in the best technology available in order to ensure the highest level of reliability. The opportunity exists to develop the standard in a manner that encourages the industry to take advantage of new technology and manage vegetation in a very proactive way. We recommend that R4 be changed as follows: Modify R4 to require Transmission Owners to immediately implement the imminent threat process defined in R1.4 when they identify instances where the CCZ is approached or encroached upon. Failure to do so would be a violation of R4. Eliminate encroachment of the CCZ as a violation of R4. This would eliminate R2 and incorporate implementation of the imminent threat process into R4. Require Transmission Owners to report to the Regional Entity on a quartely basis any instances where the imminent threat process was implemented due to an encroachment of the CCZ. This would add a reporting requirement for Transmission Operators. Require Transmission Owners to report to the Regional Entity on a quarterly basis any instances where either a momentary or sustained outage was caused by grow-ins, Active Transmission Line Right of Way blow-ins, or Active Transmission Line Right-of-Way fall-ins. This would add three additional reporting requirements for Transmission Operators. Require Regional Entities to perform additional audits of Transmission Owners that exceed metrics for violations of the CCZ . The metrics would be established in this Standard based upon 100 circuit miles of applicable lines. This would add an additional requirement for Regional Entites. This concept would result in a more rigorous standard than FAC-003-01 because of the additional reporting and auditing requirements. It would drive proactive behavior throughout the industry and provide a significant incentive for Transmisison Owners to invest in new technology such as ALS that is capable of accurately identifying vegetation that has approached or encroached upon the CCZ. We believe that this change would result in the identification of more incipient vegetation-related problems and fewer vegetation-related outages as soon as it was implemented and would best support the purpose of the Standard.
Disagree
HQT request clarification if violations of R5, R6, and R7 result in outages that must be reported. A further exception would be a sustained outage where the conductor has moved outside the critical clearance zone. This could occur under conditions of heavy icing, operating outside the line rating or excessive wind.
Agree
HQT recommends that the Standard Drafting Team review the compliance and reporting requirements for consistency and adequacy. Aplicability 4.2.3 contradict first part of Applicability 4.2.1 and that of former Applicability 4.3
Individual
Kevin Koloini
Buckeye Power, Inc.
Agree
Agree
Agreed on this question.
Agree
OK with R1. However, the active transmission line right of way seems to be a reduction in ROW width which would likely decrease reliability during the one moment when we need it most.
Agree
Agree
Agree

Agree
Agree
Agree
Agree
Agree
I agree with R2. I like the language changes, but decreasing the clearances will not improve reliability.
Agree
I understand the reasoning for the change, but I do not see how decreasing clearances will increase reliability.
Agree
Agree
Disagree
Proving vegetation is not in a clearance zone will be difficult without having third-party verification.
Agree
Agree
Group
MRO NERC Standards Review Subcommittee
Joseph Knight
GRE
Disagree
The standard specifically calls out that 200kV and higher are applicable to FAC-003. Changing to BES would imply all lines 100kV and above would be applicable.
Disagree
The MRO disagrees that the RC is appropriately positioned to identify and designate any sub-200kV lines that should be subject to this standard. The MRO believes that the lines below 200kV should include only those that are currently classified as Interconnection Reliability Operating Limit (IROL) lines which are already defined and listed for registered entities. As such R9 and R10 should be eliminated from these standards along with the RC in the applicability section.
Agree
The MRO agrees but requests further clarification on the definition of the term "Active" in Active Transmission Line R.O.W. For example: A utility has a 150 foot easement for a 230kV line and currently manages 80 feet. First; is it the intent of the standard that the utility manage the entire 150 foot easement? Second; is the entire easement considered the Active Transmission Line R.O.W?
Agree
The MRO believes that clarity was improved by separating documentation and implementation. The MRO suggests that moving the requirement for implementationt so that it immediately follows the requirement for documentation will further enhance clarity.
Agree
The MRO suggests rewording the requirement to remove ".. and environmental" . The MRO believes

that local factors includes environmental.
Agree
The MRO suggests removing the words "during the year" from sentence 1 and removing the words "within the year" in sentence 3. The MRO believes that having it only within the plan year is too restrictive.
Agree
The MRO agrees and believes that it is very important for the applicable entities to posses a Imminent Threat Procedure. The MRO also believes that the term "Imminent Threat" is subjective an should be defined.
Agree
The MRO believes that the term "interim" should be removed from R1.5. The term Interim is subjective.
Agree
The MRO agrees and fully supports the removal of Clearance 1. The MRO believes that the Gallet equation is a more effective way of determining the required clearances.
Agree
Agree
The MRO agrees and believes that the Gallet equation yeilds a less subjective measurement. The MRO believes R2 should be modified to be more definitive. The imminent threat procedure should be implemented when vegetation â€œentersâ€☐ the critical clear zone. Fines and violations for approaching the zone is not measurable or enforceable. The MRO believes that "approached" is subjective and not enforceable and should be removed from the requirement.
Agree
Agree
Agree
Disagree
The MRO believes R4 should be eliminated as vegetation contacts are covered in R5 and R6. A violation should only occur with a vegetation contact. Assessing a violation and fine for a potential reduction in system reliability is not correct. Actual contacts that trip a transmission element have some measurable impact on system reliability even if it is slight.
Agree
Agree
The MRO both Agrees and Disagrees. The MRO agrees with the separation between having an annual plan and implementing it. However, the MRO suggests removing all the words after vegetation manangement.
Individual
Joe Knight
Great River Energy
Disagree
The standard specifically calls out that 200kV and higher are applicable to FAC-003. Changing to BES would imply all lines 100kV and above would be applicable
Disagree
GRE disagrees that the RC is appropriately positioned to identify and designate any sub-200kV lines that should be subject to this standard. GRE believes that the lines below 200kV should include only those that are currently classified as Interconnection Reliability Operating Limit (IROL) lines which are

already defined and listed for registered entities. As such R9 and R10 should be eleiminated from this standards along with the RC in the applicability section.
Agree
GRE agrees but requests further clarification on the definition of the term "Active" in Active Transmission Line R.O.W. For example: A utility has a 150 foot easement for a 230kV line and currently manages 80 feet. First; is it the intent of the standard that the utility manage the entire 150 foot easement? Second; is the entire easement considered the Active Transmission Line R.O.W?
Agree
GRE believes that clarity was improved by separating documentation and implementation. GRE suggests that moving the requirement for implementationt so that it immediately follows the requirement for documentation will further enhance clarity
Agree
GRE suggests rewording the requirement to remove ".. and environmental" . GRE believes that local factors takes into account environmental.
Agree
GRE suggests removing the words "during the year" from sentence 1 and removing the words "within the year" in sentence 3. GRE believes that having it only within the plan year is too restrictive.
Agree
GRE agrees and believes that it is very important for the applicable entities to posses an Imminent Threat Procedure. GRE recomends that the Imminent Threat procedure be renamed "Vegetation Imminent Threat Procedure" so as to clearly identify the procedure in the event that a company has imminent threat procedures for more than one situation.
Agree
GRE believes that the term "interim" should be removed from R1.5. The term Interim is subjective.
Agree
GRE agrees and fully supports the removal of Clearance 1. GRE believes that the Gallet equation is a more effective way of determining the required clearances.
Agree
Agree
GRE agrees and believes that the Gallet equation yeilds a less subjective measurement. GRE believes R2 should be modified to be more definitive. The imminent threat procedure should be implemented when vegetation â€œentersâ€☐ the Critical Clearance Zone (CCZ). It is GRE's opinion that approaching the CCZ is subjective and as such very difficult to enforce.
Agree
Agree
Agree
Disagree
GRE supports the elimination of R4, as vegetation contacts are covered in R5 and R6. A violation should only occur with a vegetation contact. Assessing a violation and fine for a potential reduction in system reliability is not correct. Actual contacts that trip a transmission element have some measurable impact on system reliability even if it is slight. In the event that the SDT chooses not to eliminate R4, GRE would also support the alternative language that is shown under the second bullet.
Agree
Disagree
GRE both Agrees and Disagrees. GRE agrees with the separation between having an annual plan and implementing it. However, GRE suggests removing all the words after vegetation manangement.

Group
Midwest ISO Stakeholders Standards Collaborators
Jason L. Marshall
Midwest ISO
Disagree
By definition Bulk Electric System includes most facilities 100 to 200 kV. The previous version of this standard appropriately restricted the applicability of the standard to these facilities by requiring the Regional Reliability Organization to identify only those facilities that are critical in this voltage class. This new version of the standards attempts to limit the 100-200 kV class applicability by having the RC identify the critical facilities. We believe to have one requirement of the standard say that it applies to all the BES and then another requirement to limit the application only confuses the applicability and recommend leaving the term "electric transmission systems" in the definition.
Disagree
We do not believe that the RC is the appropriate entity to identify those facilities sub-200 kV facilities that this standard should apply to. Vegetation management is not performed in the operating horizon. Rather it is performed in the planning and operations planning horizons. The RC should not be distracted from focusing on the operating horizon by this task. We believe what the standard is essentially requiring is identifying critical facilities. There are other similar requirements such as PRC-023-1 R3 that appear to require the determination of critical facilities even though the term critical facilities is not defined. We believe this represents broader issue that requires NERC to define critical facilities. Failure to do so could result in the inefficient identification of multiple lists of critical facilities for specific requirements that may ultimately be challenged in due process.
Agree
Agree
This is a good change from a compliance perspective; the documentation requirements can now be assigned lower VRFs than the implementation requirements.
Agree
Agree
Disagree
Transmission Owners should have a Vegetation Imminent Threat Procedure, and "Vegetation Imminent Threat" should be a defined term, defined as: "Vegetation observed in the field encroaching upon a conductor within a distance that is twice the Gallet clearance distances referenced in Table I of the draft standard FAC-003-2." In this case, the threat would require an immediate response and would include communication to the Transmission Operator. From there, the actions that the operator decides to take will be dependent on the incident and system conditions. We do not need to be prescriptive with this requirement but rather allow the Transmission Operator and appropriate field personnel the flexibility to make the right decisions to safely, promptly and appropriately remove the vegetation threat. From a Transmission Owner's perspective, many situations can constitute an imminent threat but this approach will clearly define a "Vegetation Imminent Threat" as it relates to the Purpose of this standard. See our related comment on #11 below.
Agree
Agree
Agree
Disagree
he CCZ is a good theoretical concept to aid industy in understanding the overall movement of conductors, but it is an impractical concept for field application. Due to the variability in the size of the CCZ as you move along a conductor, as well as changes from span to span or even line to line

due to design parameters, loading or weather-related issues, the CCZ concept should not be tied to an imminent threat procedure. Vegetation approaching the CCZ does not constitute an imminent threat. It may be months to years before this vegetation ever gets to a proximity distance from the conductor to be within a "spark-over" distance as defined by the Gallet equations. Requirement R2 should support the purpose of this standard by requiring implementation of the Vegetation Imminent Threat Procedure when the Transmission Owner has visual, field knowledge that vegetation is encroaching upon a conductor within some specific distance that is a multiple of the Gallet distances referenced in Table I of FAC-003-2 (to be conservative we suggest two to three times the Gallet distances). Failure to implement the Vegetation Imminent Threat Procedure in such instances would be a violation of R2. As R2 is currently stated, a Transmission Owner cannot comply with R2 unless the imminent threat procedure is continuously being implemented, because vegetation that is growing is always approaching the CCZ. "Approaching the CCZ" cannot be the trigger for implementation of the Vegetation Imminent threat Procedure. Instead, the trigger should be an encroachment within some observed field distance. Requirement R2 could be reworded as follows: â€œEach Transmission Owner shall implement its Vegetation Imminent Threat Procedure when the Transmission Owner has knowledge, obtained through normal operating practices or notification from others, that vegetation is encroaching upon a conductor within a distance that is twice the Gallet clearance distances referenced in Table I." Using a multiple of the Gallet distances provides a safety factor. Assessing a violation for failure to appropriately implement the Vegetation Imminent Threat Procedure or for a sustained vegetation-related outage incents the proper behavior.
Agree
Agree
Agree
Disagree
The second bulleted alternative above is the best approach, but it should be improved by changing the imminent threat trigger from "encroachment of the CCZ" to "encroachment within some observed, field distance that is a multiple of the Gallet distances referenced in Table I". We have recommended changes to accomplish this in Requirement R2 (see our response to Question #11 above), and R4 should simply be deleted. While the CCZ is valuable to understanding the movement of conductors, it cannot be readily applied in the field. This field application challenge is noted in the Technical Reference Document (pages 29 & 30). The way R4 is currently stated, the Transmission Owner would be in violation of R4 for any CCZ encroachment not due to natural disasters or human or animal activity. This would include a tree falling from outside the right of way corridor that passes through the theoretical CCZ. Furthermore, Transmission Owners would be required to self-certify compliance with R4, and we don't think there's any way to do that. Clearly the approach of assessing violations for CCZ encroachment is unworkable. Likewise, the third alternative listed above is untenable. The tiered approach could have a mitigating effect on violations, but it would require the same inspection effort and postponement of vegetation management that makes the first alternative unworkable. Both the first and third alternatives would require very significant additional expenditures for surveys and documentation in an impossible attempt to certify compliance - money that would be better spent controlling vegetation.
Agree
Agree
We recommend striking the words "within the extent of its easement and/or legal rights". The emphasis for this requirement is to execute the annual work plan. The white paper already speaks to the point that it is a best practice for utilities to exercise their legal rights. By tagging the words on to the requirement, we are adding unnecessary compliance validation to this requirement for both industry and the regulators. By the way this is written, it could be interpreted different ways. If we agree that the goal is to prevent outages, then we can simply end this requirement with "accomplish the purpose of the standard". Each TO would be accountable to manage compliance with this standard and public relations in their service area.

FAC-003-1 lacks clarity that is essential for understanding what is necessary for compliance. The proposed FAC-003-2 needs to be simplified to aid with field implementation and compliance interpretation. Currently, it does not provide the clarity and simplification needed by Transmission Owners and regulatory bodies to enhance reliability.
Group
SERC Compliance Staff
John Wolfmeyer
SERC Reliability Corp
Disagree
The definition of the Bulk Electric System generally includes all lines operated at 100 kV and above and may exclude radial lines to load only. The standard is applicable to lines operated at greater than 200 kV regardless of their function. SERC staff does not believe that it is the intent of the standard to address lines operated at less than 200 kV unless they are deemed to be critical to the operation of the BES nor do we believe it is the intent to exclude radials to load only from the applicability. Use of the term Bulk Electric System will cause unnecessary confusion to the industry concerning applicability of this standard. Therefore, we recommend the continued use of the undefined term "electric transmission systems."
Agree
Agree
Agree
Agree
Agree
Disagree
SERC staff agrees with the concept of an imminent threat procedure, but disagrees with this requirement in its current form. The use of the word "immediate" is ambiguous. There are many conditions or threats that may require immediate removal, but would not require communication with the Transmission Operator and may require communication with another entity. SERC staff suggests that the proper communication paths be outlined by the Transmission Owner. Imminent threats should be a defined term, however SERC staff has not developed an objective, unambiguous definition.
Agree
Agree
Agree
Disagree
SERC staff agrees that the implementation of an imminent threat procedure may be a valid concept; however visualization of the Critical Clearance Zone and determining an approaching encroachment will be difficult from a practical matter. There also needs to be definition of what is meant by "approaching" if this is used. While it may be a technically sound approach to designate the clearance zone to be tied to the conductor movement envelope as found in the NESC, this results in a banana-shaped zone that is difficult to substantiate in the field by entity and compliance personnel. It may be better, and more reasonable to define a constant zone around a conductor that would be the same throughout the span. The clearance zone should not include the limitation that the zone cannot extend outside the active right of way.
Disagree

While the actual sparkover distance may be more correctly calculated using the Gallet equations, SERC staff believes it is a less conservative approach to the goal of preventing vegetation related outages. If the concept of the CCZ will remain in the standard, we suggest that the tables based on the Gallet equations be removed from the standard and be kept in the technical white paper solely to assist in developing a common understanding of the theory behind the establishment of a CCZ. However, the CCZ will continue to be a very difficult, if not impossible, aspect of the standard to implement from the perspective of practical application and compliance enforcement.
Agree
Agree
Disagree
The concept of the Critical Clearance Zone is useful as a mental model to visualize required vegetation management work. While this is a good conceptual tool to drive consistent terminology and proper vegetation management practices, it is impractical to measure on a span by span basis. The complexity of determining an encroachment into the Critical Clearance Zone is overly burdensome due to the need for survey accuracy measurements and engineering evaluations. While it may be a technically sound approach to designate the clearance zone to be tied to the conductor movement envelope as found in the NESC, this results in a banana-shaped zone that is difficult to substantiate in the field by entity and compliance personnel. We suggest that the Critical Clearance Zone concept be kept in the technical white paper and that all references to the Critical Clearance Zone be removed from the body of the standard.
Agree
Agree
Vegetation management practices should be extended areas outside of the active rights-of-way (ROW) to the extent necessary to prevent vegetation-related outages. This should include the identification and removal of trees that could impact transmission line operation similar to the practice of identifying danger trees off of the ROW. The requirement as written could serve to reward those entities that, for whatever reason, have insufficient right-of-way widths. From a practical perspective, it should not be necessary to perform clear cutting of non-active ROW, but Entities should be held responsible for any outages that occur due to contact with vegetation within their legal rights to control.
SERC staff continues to find the Applicability section of the standard to be confusing and contentious. While we recognize it is the intent this section to make the standard applicable t all entities that own transmission lines that operate at greater than 200 kV, this section should not be written to be applicable to transmission lines. Only registered entities can be held accountable for compliance with the standards. SERC staff believes the applicability should be rewritten to include Transmission Owners, Distribution Providers, and Generation Owners that own transmission lines with the characteristics defined in Section 4.2. This would eliminate the need to make register, for example, a Distribution Provider that own a 230 kV line that serves load as a Transmission Owner and make them subject to the requirements of FAC-001 and FAC-002. SERC Staff also suggest the applicability could be handled as it is in PRC-005-1 where the applicability is qualified as 'distribution provider that owns...' and 'generator owner that owns...' or in a similar manner that captures the appropriate subgroup but does not include unintended entities. SERC Staff believes a flashover between vegetation and overhead ungrounded supply conductors that occurs, whether or not the flashover results in a Sustained Outage, is clear evidence of an unallowable encroachment of vegetation into the space that should be avoided and thus should be identified as evidence of a violation of the standard. SERC staff has also found that excluding outages resulting from "earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Ownerâ€¦" results in inconsistencies in reporting because of the inconsistency of the Transmission Owners' definitions of same. If such exceptions are to be allowed, a consistent method of determining the acceptability of those exemptions should be pursued.

Consideration of Comments on 1st Draft FAC-003-2 Vegetation Management SDT — Project 2007-07

The Vegetation Management Standard Drafting Team (VM SDT) thanks all commenters who submitted comments on the 1st draft of FAC-003-2 — Transmission Vegetation Management Program standard. This standard was posted for a 30-day public comment period from October 27, 2008 through November 25, 2008. Stakeholders were asked to provide feedback on the standard through a special Standard Comment Form. There were more than 60 sets of comments, including comments from more than 100 different people from over 60 companies representing each of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

Key differences between first posting and second posting of proposed FAC-003 -2 include:

- Replaced the CCZ concept found in R4 with a practical field measurement to address commenter's concerns.
- Eliminated the CCZ as the trigger of imminent threat in R2 to address commenter's concerns.
- Added a sub part to the TVMP (1.6) in order to address commenter's concerns regarding the elimination of Clearance 1. This change requires that the TO account for anticipated conductor movement.
- Developed VRF's and VSL's consistent with the NERC Drafting Team Guidelines.
- Created a second grow-in outage requirement to allow for different VRF levels based on the actual criticality of the line.

There were 3 strong minority views not resolved:

- Some commenters disagreed with the "zero tolerance" nature of the existing in-force standard.
- Some commenters disagreed with a minimum Vegetation Inspection frequency of one year.
- Some commenters want to retain Clearance 1 that is in the existing in-force standard.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — Transmission Owners, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	John Neagle	Associated Electric Cooperative Inc.	✓				✓	✓				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chris Bolick		SERC	1, 5, 6
2.	John Bussman		SERC	1, 5, 6
3.	Ralph Schulte		SERC	1, 5, 6
4.	Ted Hilmes		SERC	1, 5, 6
5.	John Settle		SERC	1, 5, 6
6.	Kevin White		SERC	1, 5, 6
7.	John Stickley		SERC	1, 5, 6
8.	Gary Highfill		SERC	1, 5, 6
9.	Jeff Neas		SERC	1, 5, 6
10.	Craig Thomas		SERC	1, 5, 6

			1	2	3	4	5	6	7	8	9	10
2.	Guy Zito	NPCC										✓

	Additional Member	Additional Organization	Region	Segment Selection

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ralph Rufrano	New York Powerm Authority	NPCC	5
2.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
3.	Rick White	Northeast Utilities	NPCC	1
4.	Greg Campoli	New York Independent System Operator	NPCC	2
5.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
6.	Chris De Graffenried	Consolidate Edison Co. of New York, Inc.	NPCC	1
7.	Don Nelson	Massachusetts Dept. of Public Utilities	NPCC	9
8.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
9.	Brian Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	Brian Evans-Mongeon	Utility Services, LLC	NPCC	6
13.	Mike Gildea	Constellation Energy	NPCC	6
14.	Lee Pedowicz	NPCC	NPCC	10

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Linda Perez	WECC Reliability Coordination										
4.	Jerry Paulson	Western Area Power Administration, Upper Great Plains Region										
5.	Jack Gardner (Chairman) Joe Spencer (SERC staff)	SERC Vegetation Management Subcommittee (VMS)										

	Additional Member	**Additional Organization**	**Region**	**Segment Selection**
1.	**Jack Gardner**	**Progress Energy Carolinas**	**SERC**	
2.	**Randy Gann**	**Alabama Power Co.**	**SERC**	
3.	**John Neagle**	**Associated Electric Cooperative, Inc.**	**SERC**	
4.	**Robby Trimble**	**E.ON U.S. Services Inc. for LG&E & KU Companies**	**SERC**	
5.	**Ralph Hale**	**Entergy**	**SERC**	
6.	**Marc Tunstall**	**Fayetteville Public Works Commission**	**SERC**	
7.	**Reggie Wallace**	**Fayetteville Public Works Commission**	**SERC**	

8.	Jerry Lindler	South Carolina Electric and Gas Company	SERC		
9.	Richard Dearman	Tennessee Valley Authority	SERC		
10.	Billy George	Duke Energy Carolinas	SERC		

	Commenter	Organization	Industry Segment 1	2	3	4	5	6	7	8	9	10
6.	John Pinney	Progress Energy Florida	✓		✓		✓					

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Crews		FRCC	1, 3, 5

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Michael Gammon	Kansas City Power & Light	✓		✓		✓					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Todd Fridley		SPP	1, 3, 5
2.	Paul Beaulieu		SPP	1, 3, 5
3.	Duane Anstaett		SPP	1, 3, 5
4.	Gary O'Neil		SPP	1, 3, 5

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Ron Turley	Western Area Power Administration, Rocky Mountain Region	✓								✓	
9.	Jack Gardner	Progress Energy Carolinas	✓		✓		✓					
10.	Samuel Stonerock	Southern California Edison Company	✓		✓			✓				
11.	Jim Griffith	SERC OC Standards Review Group	✓		✓		✓					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Case	Entergy	SERC	1, 3, 5
2.	John Neagle	Assoc. Electric Coop., Inc.	SERC	1, 3, 5
3.	Greg Rowland	Duke Energy-Carolinas	SERC	1, 3, 5
4.	Bill Thompson	Dominion Virginia Power	SERC	1, 3, 5
5.	John Rembold	Southern Illinois Power Coop.	SERC	1, 3, 5
6.	Jason Marshall	Midwest ISO	SERC	2

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
7. Randy Castello	Mississippi Power Co.	SERC 1, 3, 5										
8. Jimmy Etheridge	Georgia Transmission Corp.	SERC 1										
9. Danny Dees	Municipal electric Authority of Ga.	SERC 1, 3, 5										
10. Glenn Stephens	South Carolina Public Service Auth.	SERC 1, 3, 5										
11. Glen Thweatt	Big Rivers Electric Coop.	SERC 1, 3, 5										
12. Gerald Beckerle	Ameren	SERC 1, 3, 5										
13. Sam Holeman	Duke Energy - Carolinas	RFC 1, 3, 5										
14. Melinda Montgomery	Entergy	SERC 1, 3, 5										
15. Roman Carter	Southern Company	SERC 1, 3, 5										
12.	Mike Neal	Western Utility Arborists	✓				✓				✓	
13.	John Tamsberg	Florida Power & Light	✓									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Eduardo Devarona	Florida Power & Light	FRCC	1
2.	Silvia Parada-Fortum	Florida Power & Light	FRCC	1
3.	Brian J. Murphy	Florida Power & Light	FRCC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Terry L. Blackwell	Santee Cooper	✓									

	Additional Member	Additional Organization	Region	Segment Selection
1.	S. T. Abrams	Santee Cooper	SERC	1
2.	Ben Fleming	Santee Cooper	SERC	1
3.	Kenny Sott	Santee Cooper	SERC	1
4.	Jim Peterson	Santee Cooper	SERC	1
5.	Glenn Stephens	Santee Cooper	SERC	1
6.	Kristi Boland	Santee Cooper	SERC	1
7.	Rene' Free	Santee Cooper	SERC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Roman Carter	Southern Company	✓		✓							

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Steve Burns	Gulf Power Co.	SERC	3
2.	Nancy Huddleston	Georgia Power Co.	SERC	3
3.	Ronald Reinike	Mississippi Power Co.	SERC	3
4.	Randall Gann	Alabama Power Co.	SERC	3
5.	Marc Butts	Southern Co. Transmission	SERC	1
6.	Raymond Vice	Southern Co. Transmission	SERC	1
7.	JT Wood	Southern Company Transmission	SERC	1
8.	Jim Busbin	Southern Co. Transmission	SERC	1
9.	Chris Wilson	Southern Co. Transmission	SERC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Charles Yeung	IRC Standards Review Committee		✓								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Patrick Brown	PJM	RFC	2
2.	Jim Castle	NYISO	NPCC	2
3.	Dan Rochester	IESO	NPCC	2
4.	Matt Goldberg	IEONE	NPCC	2
5.	Lourdes Estrada-Salinero	CAISO	WECC	2
6.	Anita Lee	AESO	WECC	2
7.	Steve Myers	ERCOT	ERCOT	2
8.	Bill Phillips	MISO	RFC	2

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Brent Ingebrigtson	E.ON U.S.	✓		✓		✓	✓				
18.	Denise Koehn	Bonneville Power Administration	✓		✓		✓	✓				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Jamrog	Vegetation/Access Road Mgmt	WECC	1
2.	Jerry Reding	Transmission Engineering	WECC	1
3.	Don Swanson	Transmission Line Maintenance Technical Svcs	WECC	1
4.	Michael Staats	Transmission Engineering	WECC	1

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10

5.	Steven Bottemiller	Real Property Support Svcs	WECC	1
6.	Marian Wolcott	Real Property Svcs	WECC	1
7.	Jennifer Bailey	Transmission Line Maintenance Technical Svcs	WECC	1
8.	Stephen Larson	Legal	WECC	1
9.	Allen Chan	Legal	WECC	1
10	Robin Furrer	Transmission Field Services	WECC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19.	Jeffrey C. Mueller	Public Service Electric and Gas Company	✓		✓							
20.	Sam Ciccone	FirstEnergy	✓		✓	✓	✓	✓				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charles Olenik	FE	RFC	1
2.	Shawn Standish	FE	RFC	1
3.	Rebecca Spach	FE	RFC	1
4.	Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
21.	Joseph Knight	MRO NERC Standards Review Subcommittee	✓		✓		✓	✓				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Neal Balu	WPS	MRO	3, 4, 5, 6
2.	Terry Bilke	MISO	MRO	2
3.	Carol Gerou	MP	MRO	1, 3, 5, 6
4.	Jim Haigh	WAPA	MRO	1, 6
5.	Charles Lawrence	ATC	MRO	1
6.	Ken Goldsmith	ALTW	MRO	4
7.	Terry Harbour	MEC	MRO	1, 3, 5, 6
8.	Pam Sordet	XCEL	MRO	1, 3, 5, 6
9.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
10.	Eric Ruskamp	LES	MRO	1, 3, 5, 6

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10

11. Joe DePoorter	MGE	MRO	3, 4, 5, 6
12. Larry Brusseau	MRO	MRO	10
13. Michael Brytowski	MRO	MRO	10

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
22.	Jason L. Marshall	Midwest ISO Stakeholders Standards Collaborators		✓								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Cyrulewski	JDRJC Associates	RFC	8
2.	Greg Rowland	Duke Energy	SERC	1, 3, 5, 6
3.	Kirit Shah	Ameren	SERC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
23.	John Wolfmeyer	SERC Compliance Staff										✓
24.	JAMES W. SMITH	ITC HOLDINGS	✓									
25.	Richard Dearman	Tennessee Valley Authority	✓	✓	✓		✓				✓	
26.	Chris Scanlon	Exelon	✓		✓		✓		✓			
27.	Weston Davis	Central Maine Power Company	✓									
28.	Thad Ness	American Electric Power (AEP)	✓		✓		✓	✓				
29.	Deborah Schaneman	Platte River Power Authority	✓		✓		✓					
30.	Alan Gale	City of Tallahassee	✓		✓		✓					
31.	Fred Young	Northern California Power Agency (NCPA)				✓						
32.	Jason Lietz	Northern Indiana Public Service Company	✓									
33.	Chip Turner	Tampa Electric Company	✓		✓		✓					
34.	Edward Bedder	Orange and Rockland Utilities Inc.	✓									

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
35.	Jason Shaver	American Transmission Company	✓									
36.	Alice Druffel	Xcel Energy	✓		✓		✓	✓				
37.	Jeff Hackman	Ameren	✓		✓		✓	✓				
38.	John Humphrey	Nebraska Public Power District	✓									
39.	Jonathan Appelbaum	Long Island power Authority	✓									
40.	Robert (Bob) B. Suedkamp	USDA Forest Service, Southwestern Region, Regional Office for AZ and NM									✓	
41.	Kris Manchur	Manitoba Hydro	✓		✓		✓	✓				
42.	Jianmei Chai	Consumers Energy Company			✓	✓	✓					
43.	Dawn Travalini	National Grid	✓									
44.	Stephen Tankersley	Pacific Gas & Electric Co.	✓				✓					
45.	Rich Salgo	NV Energy (fka Sierra Pacific / Nevada Power Co.)	✓									
46.	Patricia vanMidde	San Diego Gas & Electric	✓		✓		✓					
47.	David Kiguel	Hydro One Networks Inc.	✓		✓							
48.	David Dworzak	Edison Electric Institute										
49.	George Czerniewski	Consolidated Edison Company of New York (CECONY)	✓									
50.	Tom Mathews and Steve Rueckert	WECC										✓

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
51.	Sreenath Thota	Arizona Public Service Company	✓	✓	✓	✓	✓	✓	✓	✓		
52.	Patrick Brown	PJM Interconnection		✓								
53.	William T. Rees	Baltimore Gas & Electric Company	✓									
54.	Greg Rowland	Duke Energy Corporation	✓		✓		✓	✓				
55.	Michael Pakeltis	CenterPoint Energy	✓									
56.	Ed Davis	Entergy Services	✓		✓		✓	✓				
57.	Anita Lee	Alberta Electric System Operator		✓								
58.	Richard Kafka	Pepco Holdings, Inc	✓		✓		✓	✓				
59.	Virginia Cook and Kim Wheeler	JEA	✓		✓		✓					
60.	Dan Rochester	Independent Electricity System Operator		✓								
61.	Karen Powell	Salt River Project	✓		✓		✓	✓				
62.	Rick White	Northeast Utilities	✓									
63.	Roger Champagne	Hydro-Québec TransEnergie (HQT)	✓									
64.	Kevin Koloini	Buckeye Power, Inc.			✓	✓	✓					
65.	Joe Knight	Great River Energy	✓		✓		✓	✓				

1. In the Purpose Statement the term "electric transmission systems" was changed to Bulk Electric System, and the Purpose statement was shortened by moving the various explanatory objectives to other locations in the revised Standard. Do you agree with the purpose statement? If not, please explain.

Summary Consideration: The SDT revised the purpose statement based on industry comments. The SDT returned to "electric transmission system" based on the comments that indicated confusion with the use of "BES". The SDT also inserted the word "those" in front of the phrase "vegetation-related outages" to clarify that not all vegetation-related outages lead to cascading. The revised purpose statement now reads:

Purpose: To improve the reliability of the electric transmission system by preventing those vegetation related outages that could lead to Cascading.

Organization	Agree?	Question 1 Comment
Associated Electric Cooperative Inc.	Disagree	The definition of Bulk Electric System includes most transmission lines operated at 100 kv and above. While Section A.4.2.1 limits the applicability of FAC-003-2 to 200 kv and higher transmission lines, the use of the term Bulk Electric System could cause unnecessary confusion. Associated Electric Cooperative Inc recommends the continued use of the term "electric transmission systems."
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
SERC Vegetation Management Subcommittee (VMS)	Disagree	The definition of the Bulk Electric System generally does not include radial transmission lines directly serving load and, in addition, includes all lines operated at 100 kV and above. Use of the term Bulk Electric System will cause unnecessary confusion to the industry concerning applicability of this standard. Therefore, we recommend the continued use of the undefined term "electric transmission systems."
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Progress Energy Florida	Disagree	The intent of the revision of the standard was to bring clarity to the standard. Referring to the BES in the purpose creates confusion as to the applicability of the standard. Therefore, Progress Energy recommends the continued use of the term "electric transmission systems."
Response: The SDT thanks you for your comment Based on the comments received, the SDT understands there may be confusion caused by "BES"		

Organization	Agree?	Question 1 Comment
and has revised the purpose statement to delete BES and return to electric transmission system.		
Kansas City Power & Light	Disagree	The definition of the bulk electric system does not match the scope of the systems covered by the vegetation management standard. If the term bulk electric system is used , it should exclude the areas not covered by the standard.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by “BES” and has revised the purpose statement to delete BES and return to electric transmission system.		
Western Area Power Administration, Rocky Mountain Region	Disagree	Use of the general term Bulk Electrical System creates unintentional confusion regarding the applicability of this standard to lines operated at 200 kV or higher and designated lines operated below 200 kV.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by “BES” and has revised the purpose statement to delete BES and return to electric transmission system.		
Progress Energy Carolinas	Disagree	The intent of the revision of the standard was to bring clarity to the standard. Referring to the BES in the purpose creates confusion as to the applicability of the standard. Therefore, Progress Energy recommends the continued use of the term "electric transmission systems."
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by “BES” and has revised the purpose statement to delete BES and return to electric transmission system.		
SERC OC Standards Review Group	Disagree	The following comments are supplied by the SERC OC Standards Review Group (OCSRG): The definition of the Bulk Electric System generally does not include radial transmission lines directly serving load. The current standard covers all 200 kV and above transmission lines along with those lower voltage lines designated by the RRO while the BES includes all lines 100 kV and above. Use of the term Bulk Electric System will cause unnecessary confusion to the industry concerning applicability of this standard. Therefore, the SERC OCSRG recommends the continued use of the undefined term "electric transmission systems."
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by “BES” and has revised the purpose statement to delete BES and return to electric transmission system.		
Florida Power & Light	Disagree	The Purpose Statement of any regulation or standard should be completely consistent with the body of regulation or standard. Here the use of Bulk Electric System (which is defined as 100 kV and above) is inconsistent with the language of the Standard that states this Standard applies to 200 kV and above. One of the primary purposes of re-

Organization	Agree?	Question 1 Comment
		drafting a Reliability Standard is to clear up any previous confusion -- here the Purpose Statement instead of adding to clarity, adds an unnecessary element of confusion. Thus, the Purpose Statement should be re-written to state 200 Kv and above.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES". Rather than create a new class of BES (>200kv), the SDT revised the purpose statement to delete BES and return to electric transmission system.		
Southern Company	Disagree	The initial FAC-003-1 drafting team had a particular reason for not using Bulk Electric System for fear of it being widely recognized to characterize the entire networked transmission system. This reason was to limit possible confusion with the applicability of the Standard. The Bulk Electric System definition includes all lines of the grid operated at 100 kV and above. This term also does not necessarily include lines of any voltage class that are radial and directly serving load. Use of this term in lieu of "electric transmission systems" has the potential to cause additional confusion to the industry.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
E.ON U.S.	Disagree	The definition of the Bulk Electric System generally does not include radial transmission lines directly serving load and, in addition, includes all lines operated at 100 kV and above. Use of the term Bulk Electric System will cause unnecessary confusion to the industry concerning applicability of this standard. Therefore, we recommend the continued use of the undefined term "electric transmission systems."
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
MRO NERC Standards Review Subcommittee	Disagree	The standard specifically calls out that 200kV and higher are applicable to FAC-003. Changing to BES would imply all lines 100kV and above would be applicable.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Midwest ISO Stakeholders Standards Collaborators	Disagree	By definition Bulk Electric System includes most facilities 100 to 200 kV. The previous version of this standard appropriately restricted the applicability of the standard to these facilities by requiring the Regional Reliability Organization to identify only those facilities that are critical in this voltage class. This new version of the standards attempts to limit the 100-200 kV class applicability by having the RC identify the critical facilities. We believe to have one requirement of the standard say that it applies to all the BES and then another requirement to limit the

Organization	Agree?	Question 1 Comment
		application only confuses the applicability and recommend leaving the term "electric transmission systems" in the definition.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
SERC Compliance Staff	Disagree	The definition of the Bulk Electric System generally includes all lines operated at 100 kV and above and may exclude radial lines to load only. The standard is applicable to lines operated at greater than 200 kV regardless of their function. SERC staff does not believe that it is the intent of the standard to address lines operated at less than 200 kV unless they are deemed to be critical to the operation of the BES nor do we believe it is the intent to exclude radials to load only from the applicability. Use of the term Bulk Electric System will cause unnecessary confusion to the industry concerning applicability of this standard. Therefore, we recommend the continued use of the undefined term "electric transmission systems."
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
ITC HOLDINGS	Disagree	ITC does not agree with the new purpose statement. The NERC Glossary of terms states that the BES ?.generally operated at voltages of 100kV or higher and the Applicability in Section 4 clearly states the standard is intended to apply to all line voltages of 200kV and above and those lines designated by the Reliability Coordinator (4.2.1) as being subjected to this standard. Using the term Bulk Electric System (BES) clearly sends a confusing message and should be eliminated. Thus the term of "electric transmission system" is appropriate for the standard
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Tennessee Valley Authority	Disagree	TVA feels the use of the term Bulk Electric System will cause unnecessary confusion to the industry concerning applicability of this standard. TVA recommends the continued use of the undefined term "electric transmission systems. TVA recommends changing the phrase "by preventing vegetation-related outages that could lead to Cascading" to "by preventing those vegetation-related outages that could lead to Cascading", this removes the improper inference that each vegetation-related outage leads to Cascading
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system. Additionally, at your suggestion and that of others, the SDT has added the qualifying word "those" to define that the standard should address interconnection reliability and security.		

Organization	Agree?	Question 1 Comment
Central Maine Power Company	Disagree	Central Maine Power suggests that a definition be provided for Bulk Power.
Response: The SDT is uncertain of the need to define Bulk Power.		
American Electric Power (AEP)	Disagree	American Electric Power ("AEP") does not agree with this purpose statement. First, it is clear from the Applicability (in Section 4) that the standard applies only to certain lines, not to the entire Bulk Electric System (BES). Reference to the BES in the Purpose statement tends to muddy the water, potentially leading to an assumption that the Standard indeed applies to the entire BES. AEP suggests that the term BES used herein be replaced with "electric transmission system" or "transmission grid". Second, the phrase "by preventing vegetation-related outages that could lead to Cascading" should be changed to "by preventing those vegetation-related outages that could lead to Cascading", to remove any suggestion that all vegetation-related outages could lead to Cascading.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by “BES” and has revised the purpose statement to delete BES and return to electric transmission system. Additionally, at your suggestion and that of others, the SDT has added the qualifying word “those” to define that the standard should address interconnection reliability and security.		
Tampa Electric Company	Disagree	NERC glossary of terms defines the Bulk Electric System as "the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher." This, at a minimum, could lead to confusion over what impacts the reliability of the Grid by potentially including facilities less than 200 kV.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by “BES” and has revised the purpose statement to delete BES and return to electric transmission system.		
Orange and Rockland Utilities Inc.	Disagree	The use of the term "Bulk Electric System" (BES) could lead to confusion. In most regions BES includes lines with operating voltages equal to or greater than 100kV. The Standard is intended to apply to all lines with operating voltages equal to or greater than 200kV, and only those sub-200kV lines which are designated by the Reliability Coordinator (paragraph 4.2.1). Use of the words "electric transmission systems" rather than BES would eliminate this potential source of confusion.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by “BES” and has revised the purpose statement to delete BES and return to electric transmission system.		
American Transmission	Disagree	ATC disagrees with changing the term "electric transmission systems" to "Bulk Electric System". This standard applies to 200 kV and higher transmission lines not all BES facilities. Suggested Purpose statement: To maintain

Organization	Agree?	Question 1 Comment
Company		the reliability of the electric transmission system by requiring entities to have and implement a transmission vegetation management plan.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system. We also appreciate your suggested purpose statement but based on others' comments to be more specific about the reliability need for this standard we modified the purpose statement as seen in the Summary Consideration above.		
Ameren	Disagree	By definition, the capitalized term, Bulk Electric System, is defined to include most facilities 100 kV and above. The previous version of this standard appropriately restricted the applicability of the standard to those facilities operating above 200kV and any additional facilities identified by the Regional Reliability Organization as critical. This new version of the standards attempts to limit the 100-200 kV class applicability by having the RC identify the critical facilities. We believe the change creates unnecessary and undesirable confusion in that one requirement of the standard says that it applies to all the BES and then another requirement limits the application. Leaving the term "electric transmission systems" in the definition is preferable to that proposed.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Nebraska Public Power District	Disagree	NPPD disagrees with the change to bulk electric system, because it creates confusion on the applicability. This standard only applies to certain lines and not the entire (bulk) system.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Manitoba Hydro	Disagree	Manitoba Hydro disagrees with changing "electric transmission systems" to "Bulk Electric System" because BES applies to facilities 100kV and above which may not have an impact on system reliability.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Consumers Energy Company	Disagree	Consumers Energy disagrees with changing the current "electric transmission systems" to "bulk electric system". This change will create confusion and can lead to a discrepancy concerning lines operating below 200kV that may be included in the "bulk electric system" but are otherwise excluded from this standard.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES"		

Organization	Agree?	Question 1 Comment
and has revised the purpose statement to delete BES and return to electric transmission system.		
National Grid	Disagree	Use of the term Bulk Electric System will cause unnecessary confusion to the industry concerning applicability of this Standard.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Edison Electric Institute	Disagree	The purpose of the standard should be revised to state 'To maintain minimum clearances sufficient to avoid any vegetation-related Sustained Outages for all applicable conditions.' This is the identical wording taken from Order No. 693, Paragraph 731.
Response: The SDT appreciates your comments to use the exact wording in the FERC Order for the purpose statement. However, the SDT believes strongly that the interconnected system reliability which FERC should be protecting is better defined by the second posting statement. For instance, there are 200 kV circuits which serve only local load. Outages to these circuits from vegetation are no different than from other causes. The issue for this standard should be the prevention of vegetation outages that will threaten the interconnection.		
Consolidated Edison Company of New York (CECONY)	Disagree	The phrase "Bulk Electric System" (BES) is somewhat misleading. BES includes transmission voltages greater than 100kV but this Standard addresses transmission lines with operating voltages at or above 200kV and only those lines below 200kV designated by the Reliability Coordinator. Use of the phrase "electric transmission circuits" or something similar rather than BES would reduce confusion.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Arizona Public Service Company	Disagree	APS suggest the following change; To improve the reliability of the Bulk Electric System by preventing vegetation related outages. This is a reliability standard APS would suggest removing "that could lead to widespread cascading failures" from the purpose statement.
Response: The SDT thanks you for your comment. However, the SDT believes strongly that the interconnected system reliability which FERC should be protecting is better defined by the second posting statement. For instance, there are 200 kV circuits which serve only local load. Outages to these circuits from vegetation are no different than from other causes. The issue for this standard should be the prevention of vegetation outages that will threaten the interconnection.		
Duke Energy Corporation	Disagree	Duke disagrees with changing "electric transmission systems" to "Bulk Electric System" because this creates the potential for confusion or indiscriminate expansion of the scope of applicability to 100kV facilities which may not

<table>
<tr><th>Organization</th><th>Agree?</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>have an impact on network system reliability. Using "Bulk Electric System" confuses the applicability of the standard. Duke believes that Section 4.2 has the specificity to clearly designate any applicable lines. Thus, the term "electric transmission systems" is appropriate.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by “BES” and has revised the purpose statement to delete BES and return to electric transmission system.</td></tr>
<tr><td>Entergy Services</td><td>Disagree</td><td>Entergy disagrees with changing “electric transmission systems” to “Bulk Electric System.” Historically, the definition of the Bulk Electric System has included all lines operated at voltages 100 kV and greater. The above change in terminology will add ambiguity to which lines this standard is applicable. Entergy is concerned about the potential for this ambiguity leading to the expansion of the applicability of the standard to include lines below 200kv.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by “BES” and has revised the purpose statement to delete BES and return to electric transmission system.</td></tr>
<tr><td>JEA</td><td>Disagree</td><td>We disagree with this change as it may cause confusion on the applicability of the standard as the BES is generally 100kV and above, but this standard generally applies to 200kV and above.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by “BES” and has revised the purpose statement to delete BES and return to electric transmission system.</td></tr>
<tr><td>Great River Energy</td><td>Disagree</td><td>The standard specifically calls out that 200kV and higher are applicable to FAC-003. Changing to BES would imply all lines 100kV and above would be applicable</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by “BES” and has revised the purpose statement to delete BES and return to electric transmission system.</td></tr>
<tr><td>Western Area Power Administration, Upper Great Plains Region</td><td>Agree</td><td>Western (UGPR) agrees with the objective of using the FERC/NERC defined term "Bulk Electric System", but believe that the FERC/NERC definition includes lines above 100 kV. It needs to be clearly understood that use of the generic term in the Purpose section does not supersede the specific definitions (greater than 200 kV, etc.) contained in the Facilities section.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by “BES” and has revised the purpose statement to delete BES and return to electric transmission system based on a overwhelming industry preference for the latter.</td></tr>
</table>

Organization	Agree?	Question 1 Comment
Platte River Power Authority	Agree	The use of the approved terminology, Bulk Electric System, from the NERC Glossary of Terms is better than the undefined term electric transmission systems.
Response The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by “BES” and has revised the purpose statement to delete BES and return to electric transmission system based on a overwhelming industry preference for the latter.		
Northeast Utilities	Agree	Agree with the term "bulk electric system. "Disagree with the wording of the Purpose Statement; The Purpose statement reads "To improve the reliability of the bulk electric system by preventing vegetation related outages that could lead to Cascading." One vegetation-caused outage does not in and of itself cause Cascading. Cascading will only result due to a combination of events - either multiple vegetation outages during the same time or an outage coupled with equipment malfunction or operational errors. The document seems to be internally inconsistent in this regard. The Technical Reference for FAC-003-2 notes that outages due to trees falling from outside the right-of-way or other outage causes on a critical facility would not constitute a possible cascading effect. If one occurrence of these types of outages would not constitute a cascading potential then one must wonder why an outage from a tree contact within the right-of-way is considered a possible cascading event? Suggest rewording the statement to exclude the comment about Cascading and use "by preventing vegetation related outages on critical transmission facilities."
Response: The SDT thanks you for your comment. The SDT acknowledges that a single vegetation-related outage will not, in the absence of other contributing factors cause a cascading collapse of the electric grid. The intent of the standard is to prevent those vegetation-related outages that could contribute to a cascading event. Therefore based on your comment, and others’, the SDT added “those” to further refine the intent.		
Southern California Edison Company	Agree	Q1: SCE agrees in part with the proposed revisions to the purpose statement. However, we believe the phrase "vegetation related outages" is unnecessarily vague. Based on the content of certain requirements in Version 2, the intent of this standard is and should be to prevent sustained outages due to vegetation-to-line contacts. SCE respectfully suggests the purpose statement (A3) be revised to read: "To improve the reliability of the Bulk Electric System by preventing vegetation-to-line contacts that could lead to Cascading?
Response: The SDT thanks you for your comment. The SDT focuses this standard on preventing vegetation-related Sustained Outages rather than vegetation to line contacts as you recommend because not all contacts result in Sustained Outages.		
BCTC	Agree	Yes, we agree.
Western Utility Arborists	Agree	Yes, we agree.

Organization	Agree?	Question 1 Comment
Bonneville Power Administration	Agree	
FirstEnergy	Agree	
Santee Cooper	Agree	
Exelon	Agree	
City of Tallahassee	Agree	
Northern California Power Agency (NCPA)	Agree	
Northern Indiana Public Service Company	Agree	
Xcel Energy	Agree	
Long Island power Authority	Agree	
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	
Pacific Gas & Electric Co.	Agree	
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	
San Diego Gas & Electric	Agree	
Hydro One Networks Inc.	Agree	

Organization	Agree?	Question 1 Comment
NPCC	Agree	
WECC Reliability Coordination	Agree	
WECC	Agree	
Baltimore Gas & Electric Company	Agree	
CenterPoint Energy	Agree	
Pepco Holdings, Inc	Agree	
Independent Electricity System Operator	Agree	
Salt River Project	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
Buckeye Power, Inc.	Agree	
Response: The SDT thank you for your participation. The SDT made revisions to the purpose statement in response to industry comment. In order to avoid confusion the SDT replace “BES” with “electric transmission system” and inserted the word “those” in front of the phrase “vegetation-related outages”.		

2. The Reliability Coordinator was chosen as the proper entity to identify sub-200kV transmission lines to be subject to this standard (see applicability, R9, and R10). Do you agree with this choice? If not, please explain.

Summary Consideration: A majority of the commenters agreed with the selection of Reliability Coordinator to designate sub-200 kV transmission lines to which this standard applies. However several dissenters recommended the Planning Coordinator (PC) as a more appropriate choice. The stakeholders' main reason for preferring the PC is the longer time horizon that the PC normally considers in the performance of its function. Typically an RC considers the real time to months ahead operating time horizons. A PC typically takes into account a planning horizon extending out several years. An example cited by some stakeholders is the assignment to the PC for identifying applicable lines in NERC Standard PRC-023 R3 – Transmission Relay Loadability.

Upon consideration of the sound rationale for replacement of RC with PC, the SDT changed Requirement R10 and R11 as well as the applicability section 4.2 to reflect this.

Some commenters suggested that facilities critical to the derivation of an IROL should be the only criterion for selection of lines subject to this standard. The Independent System Operator - Regional Transmission Owner Council (ISO/RTO Council) and individual ISOs offered that all transmission lines of the BES are applicable under this standard regardless of voltage class or impact on the BES. However the ISO/RTO Council believes that there are other standards that determine critical facilities. The SDT agreed that including facilities critical to the derivation of an IROL would be a technically acceptable threshold to determine applicability of sub-200 kV lines, but concluded that there are other thresholds that define circuits important to the reliability of the Bulk Electric System (e.g., the WECC region's Major Transfer Paths). The SDT wishes to allow the application of other criteria in addition to IROL to support to the greatest extent possible the reliability of the BES.

Several commenters recommended the inclusion of a dispute resolution process and coordination between Transmission Owner/RC in this standard to ensure agreement and consistency across regions. The SDT believes that the language in Requirement R10 which specifies "consultation" **OR CONSENSUS** between the Planning Coordinator and its member Transmission Owners, would minimize the need for a dispute resolution process. Additionally, other Standards in which the PC determines important circuits to the reliability of the BES include no such mechanism.

Requirements R9 and R10 (now R10 and R11) were changed as follows:

R9. Each Planning Coordinator shall prepare and review annually, a list lines that are operated below 200kV, if any, which are subject to this standard. . Each Planning Coordinator shall consult with its Transmission Owner(s) and neighboring Planning Coordinators to obtain input to develop the list.

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Deleted: in consultation with its Transmission Owner(s) and neighboring Reliability Coordinator(s) shall jointly prepare and keep current

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R10. Each Planning Coordinator shall develop and document its method for assessing the reliability significance of sub-200kV lines whose loss would place the grid at an unacceptable risk of instability, separation, or cascading failures.

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Deleted: considering all of the following:¶
R10.1 Transmission lines whose loss would result in the exceedance of an Interconnection Reliability Operating Limit (IROL)¶
R10.2 Transmission lines

Organization	Agree?	Question 2 Comment
SERC Vegetation Management Subcommittee (VMS)		The SERC Vegetation Management Subcommittee (VMS) abstains on this question. However, we believe that this comment form should provide an option to abstain in addition to the options to agree/disagree.
Response: Thank you for your comment. The SDT does not believe this issue can be addressed by this team. However it is appropriate to raise this limitation with the NERC staff.		
American Transmission Company	Disagree	Requirements 9 and 10 should be deleted and replaced with the following language. Proposed Language The Transmission Owner shall include those transmission lines below 200 kV that that are associated with an established IROL. (This language could either be uses as a requirement or inserted into the Applicability section.) Our statement provides a clear decision on which lower voltage lines have to be included in an entities transmission vegetation management program.
Response: Thank you for your comments. The SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11)as well as the applicability section 4.2. The SDT believes that further guidance is needed to ensure all regions have evaluated and developed a list of sub 200kV lines that are subject to this standard. The FERC indicated that not all regions produced such lists and directed the ERO, using this stakeholder process, to develop a mechanism to provide the list. The proposed R10 continues to require consultation between the PC and Transmission Owner as well as neighboring PCs. In R10, the SDT believes that the PC has the requisite expertise and planning horizon perspective to designate sub 200kV lines to comply with this standard. Limiting the choice of lines to solely IROL lines may not achieve the purpose of this standard. The SDT intends in R10 that the PC employ a technically sound criterion when designating transmission lines to be subject to this standard which includes IROL calculations.		
Associated Electric Cooperative Inc.	Disagree	Associated Electric Cooperative Inc does not believe the Reliability Coordinator (RC) is the appropriate entity to determine whether or not selected sub-200 kv transmission lines should be subject to this standard. The planning horizon for the RC is typically much shorter than the time needed to incorporate a sub-200 kv transmission line into a vegetation management program. Associated recommends Planning Coordinator be designated as the applicable functional entity and be substituted wherever Reliability Coordinator appears in the Standard.
Response: Thank you for your comment. The SDT agrees and has replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2.		
Santee Cooper	Disagree	The RC should not define applicable lines that are operated below 200 kV. PRC023 requires the Planning Coordinator to define transmission lines operated at 100 kV to 200 kV that are considered critical to the reliability of

Organization	Agree?	Question 2 Comment
		the Bulk Electric System. Multiple lists will lead to confusion among electric utilities.
Response: Thank you for your comments. Several commenters offered sound rationale for replacement of RC with PC including a reference to NERC Standard PRC-023 Relay Loadability. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this.		
Southern Company	Disagree	The use of the Reliability Coordinator as the entity for identifying sub-200 kV lines is inconsistent with the approach used in other NERC standards, such as PRC-023. Other NERC standards utilize the Planning Coordinator or the RRO as the entity. We feel the Planning Coordinator would be the appropriate entity for identifying sub-200 kV lines covered by FAC-003-2.
Response: Thank you for your comments. Several commenters offered sound rationale for replacement of RC with PC including a reference to NERC Standard PRC-023 Relay Loadability. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this.		
SERC OC Standards Review Group	Disagree	The SERC OCSRG does not believe that the RC is the appropriate entity to identify sub-200 kV transmissions to be subject to this standard. Vegetation Management programs are longer than the normal operating horizons of RCs. We believe that the proper function to identify sub-200 kV transmission lines subject to this standard is the Planning Coordinator. This must be consistent with PRC-023, Requirement 3. We also recommend that a process be established for dispute resolution. NERC should develop a comprehensive approach to the determination of "critical" facilities rather than pushing a piecemeal approach as evidenced by this standard and PRC-023, among others.
Response: Thank you for your comments. Several commenters offered sound rationale for replacement of RC with PC including a reference to NERC Standard PRC-023 Relay Loadability. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this. In regard to dispute resolution process, the SDT believes that the requirement for consultation implies cooperation and collaboration between entities and a dispute resolution process is not currently needed. **In regard to a comprehensive approach to identify/determine "critical" facilities, the SDT agrees in concept but has some reservations. The reservations are based upon doubt that "one size can fit all" for every context of every standard. A critical facility for one situation may not be a critical facility for another. For example, the PRC standard seeks to identify facilities that may need to carry very heavy contingent flows to stop a cascade. This FAC-003 standard seeks to identify facilities for which their OUTAGE (due to vegetation) would create reliability concerns for the BES.**		
IRC Standards Review Committee	Disagree	We do not see the role of an RC or PC in a vegetation management standard. All Transmission Owners need to ensure they have a vegetation program to avoid unnecessary tripping of transmission lines, at any voltage levels and regardless of their impacts on the BES. Identification of critical facilities is not a part of this standard; it belongs to other standards that deal with SOL/IROL calculations, SPS, protection and critical infrastructure protection. R10 and

Organization	Agree?	Question 2 Comment
		R11 should be removed from the standard.
Response: Thank you for your comments. The SDT does not agree with removal of R10 and R11. The SDT does not believe the burden of compliance for low voltage circuits with little or no impact on the BES is reasonable for electricity consumers to bear. FERC has acknowledged the same and given guidance for this standard's applicability which provides that a distinction exists in sub-200 kV facilities. The SDT sought to develop a reasonable mechanism that balances these concerns when we drafted R9 and R10 (now R10 and R11). The SDT agrees with respect to use of the label "critical". This standard does not intend to classify facilities as critical, that is left to CIP-002.		
Independent Electricity System Operator	Disagree	The IESO does not see a role for an RC or PC in a vegetation management standard. All Transmission Owners need to ensure they have a vegetation program to avoid unnecessary tripping of transmission lines, particularly those that impact the BES. We are of the view that identification of critical facilities is not a part of this standard; it belongs to other standards that deal with SOL/IROL calculations, SPS, protection and critical infrastructure protection. R10 and R11 should therefore be removed from the standard.
Response: Thank you for your comments. The SDT does not agree with removal of R10 and R11. The SDT does not believe the burden of compliance for low voltage circuits with little or no impact on the BES is reasonable for electricity consumers to bear. FERC has acknowledged the same and given guidance for this standards' applicability which provides that a distinction exists in sub-200 kV facilities. The SDT sought to develop a reasonable mechanism that balances these concerns when we drafted R9 and R10 (now R10 and R11). The SDT agrees with respect to use of the label "critical". This standard does not intend to classify facilities as critical, that is left to CIP-002.		
Hydro-Quebec Transenergie (HQT)	Disagree	HQT believe that the Planning Coordinator (PC) should be the entity responsible to determine the elements part of the BPS submitted to this Standard, and in fact for all other Standards. Those elements should be determined by an impact based methodology, as used in NPCC, with no voltage limitation and no fixed voltage threshold level as imposed in Applicability 4.2.
Response: Thank you for your comments. Several commenters offered sound rationale for replacement of RC with PC. The SDT agreed with the rationale and changed Requirement R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this. The SDT believes each PC can determine the appropriate threshold to assure the reliability of the BES and does not believe it necessary to instruct PCs in this regard in this Standard.		
MRO NERC Standards Review Subcommittee	Disagree	The MRO disagrees that the RC is appropriately positioned to identify and designate any sub-200kV lines that should be subject to this standard. The MRO believes that the lines below 200kV should include only those that are currently classified as Interconnection Reliability Operating Limit (IROL) lines which are already defined and listed for registered entities. As such R10 and R11 should be eliminated from these standards along with the RC in the applicability section.
Response: Thank you for your comments. The SDT agrees that the RC is not appropriately positioned and replaced the RC with the PC. The SDT believes		

Organization	Agree?	Question 2 Comment
that further guidance is needed to ensure all regions have evaluated and developed a list of sub 200kV lines that are subject to this standard. FERC indicated that not all regions produced such lists and directed the ERO, using this stakeholder process, to develop a mechanism to provide the list. The proposed R10 continues to require consultation between the PC and Transmission Owner as well as neighboring PCs. In R10, the SDT believes that the PC has the requisite expertise and planning horizon perspective to designate sub 200kV lines to comply with this standard. Limiting the choice of lines to solely those included in the derivation of an IROL may not achieve the purpose of this standard. The SDT intends in R10 that the PC employ a technically sound criterion when designating transmission lines to be subject to this standard, which could include those included in the derivation of IROL calculations.		
Midwest ISO Stakeholders Standards Collaborators	Disagree	We do not believe that the RC is the appropriate entity to identify those facilities sub-200 kV facilities that this standard should apply to. Vegetation management is not performed in the operating horizon. Rather it is performed in the planning and operations planning horizons. The RC should not be distracted from focusing on the operating horizon by this task. We believe what the standard is essentially requiring is identifying critical facilities. There are other similar requirements such as PRC-023-1 R3 that appear to require the determination of critical facilities even though the term critical facilities is not defined. We believe this represents broader issue that requires NERC to define critical facilities. Failure to do so could result in the inefficient identification of multiple lists of critical facilities for specific requirements that may ultimately be challenged in due process.
Response: Thank you for your comments. Several commenters offered sound rationale for replacement of RC with PC including a reference to NERC Standard PRC-023 Relay Loadability. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this. Your comment on time horizon further supports this change. **In regard to a comprehensive approach to identify/determine circuits, the SDT agrees in concept but has some reservations. The reservations are based upon doubt that "one size can fit all" for every context of every standard. A critical facility for one situation may not be a critical facility for another. For example, the PRC standard seeks to identify facilities that may need to carry very heavy contingent flows to stop a cascade. This FAC-003 standard seeks to identify facilities for which their OUTAGE (due to vegetation) would create reliability concerns for the BES.**		
Ameren	Disagree	While the RC would seemingly have the wide area view to make the assignment appropriate, the standard is really trying to determine the entity who can assess the risk to the BES of a vegetation-related outage. The management of that risk is in the venue of the Transmission Planner who, in the long term, designs the system and, in the Operating Horizon, establishes the parameters of operation that will lead to reliability. Certainly, the RC is preferable to the RE (RRO). However, the TP is preferable to the RC.
Response: Thank you for your comments. Several commenters offered sound rationale for replacement of RC with PC including a reference to NERC Standard PRC-023 Relay Loadability. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this. The PC performs its function over a similarly long term time horizon as the Transmission Planner but would be better positioned as a result of the PC's wider area view.		

Organization	Agree?	Question 2 Comment
Manitoba Hydro	Disagree	Manitoba Hydro disagrees that the RC is appropriately positioned to identify and designate any sub-200kV lines that should be subject to this standard. Lines below 200kV should include only those that are currently classified as Interconnection Reliability Operating Limit (IROL) lines which are already defined and listed for registered entities. As such R10 and R11 should be eliminated from this standards along with the RC in the applicability section.
Response: Thank you for your comments. The SDT agrees that the RC is not appropriately positioned and replaced the RC with the PC in the revised draft proposed Standard. **The SDT agrees that lines included in the derivation of an IROL should be included in the PC's list; there are other lines that have importance to the reliability of the BES, e.g. the WECC Major Transfer Paths. The PC is well qualified for this differentiation task and may choose to develop thresholds which match the needs of its region. Therefore, the SDT respectfully disagrees that the only sub-200 kV circuits for which this standard should apply are those stated by MH.**		
WECC	Disagree	WECC believes the Regional Entity should remain the proper entity to identify sub-200kV transmission lines subject to this standard. The Regional Entity is in the best position to work with Transmission Owners (Transmission Owners) and Reliability Coordinators across the interconnection to determine critical sub-200kV transmission lines.
Response: Thank you for your comments. Several commenters offered sound rationale for replacement of RC with PC. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this.		
PJM Interconnection	Disagree	The RC or PC should not play a role in the vegetation management standard. All Transmission Owners need to ensure they have a vegetation program to avoid unnecessary tripping of transmission lines, at any voltage levels and regardless of their impacts on the BES. Identification of critical facilities is not a part of this standard; it belongs to other standards that deal with SOL/IROL calculations, SPS, protection and critical infrastructure protection. R10 and R11 should be removed from the standard.
Response: Thank you for your comments. The SDT does not agree with removal of R10 and R11. The SDT does not believe the burden of compliance for low voltage circuits with little or no impact on the BES is reasonable for electricity consumers to bear. FERC has acknowledged the same and given guidance for this standards' applicability which provides that a distinction exists in sub-200 kV facilities. The SDT sought to develop a reasonable mechanism that balances these concerns when we drafted R10 and R11. The SDT agrees with respect to use of the label "critical". This standard does not intend to classify facilities as critical, that is left to CIP-002		
National Grid	Disagree	No opinion.
Response: Thank you for your participation.		

Organization	Agree?	Question 2 Comment
Duke Energy Corporation	Disagree	Duke believes that the Planning Coordinator is the appropriate entity to identify any sub-200 kV facilities that this standard should apply to. Of note is the time frame once a sub-200kV line is designated, then the Transmission Owner has 12 months before the line is subject to the standard. This coincides with the longer term view of the Planning Coordinator.
Response: Thank you for your comment. Several commenters offered sound rationale for replacement of RC with PC. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this.		
Great River Energy	Disagree	GRE disagrees that the RC is appropriately positioned to identify and designate any sub-200kV lines that should be subject to this standard. GRE believes that the lines below 200kV should include only those that are currently classified as Interconnection Reliability Operating Limit (IROL) lines which are already defined and listed for registered entities. As such R10 and R11 should be eliminated from this standards along with the RC in the applicability section.
Response: Thank you for your comments. The SDT agrees that the RC is not appropriately positioned and replaced the RC with the PC in the draft proposed Standard. **The SDT agrees that lines included in the derivation of an IROL should be included in the PC's list, there are other lines that have importance to the reliability of the BES, e.g. the WECC Major Transfer Paths. The PC is well qualified for this differentiation task and may choose to develop thresholds which match the needs of its region. Therefore, the SDT respectfully disagrees that the only sub-200 kV circuits for which this standard should apply are those stated by GRE.**		
WECC Reliability Coordination	Agree	This would be a new function in WECC RC; we are not currently staffed to perform this function.
Response: Thank you for your comment. The SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2.		
Western Area Power Administration, Upper Great Plains Region	Agree	Western's (UGPR) agreement is contingent upon maintaining the requirements for consulting with Transmission Owners and neighboring Reliability Coordinator(s) and documenting the method for assessing the reliability significance of each included line as contained in R10 and R11.
Response: Thank you for your comment. The SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2. The proposed R10 continues to require consultation between the PC and Transmission Owner as well as neighboring PCs.		
Progress Energy Florida	Agree	While Progress Energy agrees that the RC is the appropriate entity, the drafting team should consider including a dispute resolution requirement for those instances when the Transmission Owner and the Reliability Coordinator disagree as to which lines below 200 kV should be included.

Organization	Agree?	Question 2 Comment
Response: Thank you for your comment. Several commenters offered sound rationale for replacement of RC with PC. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this. In regard to dispute resolution process, the SDT believes that the requirement for consultation implies cooperation and collaboration between entities and a dispute resolution process is not currently needed.		
Kansas City Power & Light	Agree	I agree with the qualification that the Reliability Coordinator identify sub-200kv facilities in consultation with its Transmission Owner(s) and neighboring Reliability Coordinator(s).
Response: Thank you for your comment. The SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2. The proposed R10 continues to require consultation between the PC and Transmission Owner as well as neighboring PCs.		
Progress Energy Carolinas	Agree	While Progress Energy agrees that the RC is the appropriate entity, the drafting team should consider including a dispute resolution requirement for those instances when the Transmission Owner and the Reliability Coordinator disagree as to which lines below 200 kV should be included.
Response: Thank you for your comment. Several commenters offered sound rationale for replacement of RC with PC. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this. In regard to dispute resolution process, the SDT believes that the requirement for consultation implies cooperation and collaboration between entities and a dispute resolution process is not currently needed.		
Southern California Edison Company	Agree	Q2: No comments.
Response: Thank you for your participation.		
Western Utility Arborists	Agree	Yes, we agree.
Response: Thank you for your comment. Please see the summary consideration – based on stakeholder comments, the SDT changed the applicability in Requirements R9 and R10 (now R10 and R11) from the Reliability Coordinator to the Planning Coordinator.		
ITC HOLDINGS	Agree	ITC agrees that the Reliability Coordinator is the appropriate entity to identify and designate any sub - 200kV lines deemed applicable to the standard with the concurrence of the Transmission Owner.
Response: Thank you for your comment. Based on other stakeholder comments, the SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2. The proposed R10 continues to require consultation between the PC and Transmission Owner as well as		

Organization	Agree?	Question 2 Comment
neighboring PCs.		
Tennessee Valley Authority	Agree	TVA agrees with Comment question 2
Response: Thank you for your comment. Based on other stakeholder comments, the SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2. The proposed R10 continues to require consultation between the PC and Transmission Owner as well as neighboring PCs.		
American Electric Power (AEP)	Agree	AEP concurs with the drafting team that the Reliability Coordinator is the appropriate entity for identifying sub-200kV lines (if any) that would be subject to the Standard.
Response: Thank you for your comment. Based on other stakeholder comments, the SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2.		
Platte River Power Authority	Agree	The Reliability Coordinator is better able to identify lines under 200 kv that would exceed an Interconnection Reliability Operating Limit (IROL), cause instability, uncontrolled separation, or cascading outages resulting from a vegetation related outage than the Regional Entity.
Response: Thank you for your comment. Based on other stakeholder comments, the SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2.		
Nebraska Public Power District	Agree	NPPD agrees that the Reliability Coordinator is the correct body for identification of any sub 200kV lines that would be subject to this standard.
Response: Thank you for your comment. Based on other stakeholder comments, the SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2.		
Consolidated Edison Company of New York (CECONY)	Agree	CECONY agrees provided that R10 remains the same as is currently written. This states that the Reliability Coordinator, in consultation with the Transmission Owner, shall jointly prepare and keep current, a list of designated applicable lines.
Response: Thank you for your comment. Based on other stakeholder comments, the SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2. The proposed R10 continues to require consultation between the PC and Transmission Owner as well as neighboring PCs.		

Organization	Agree?	Question 2 Comment
Northeast Utilities	Agree	One question: Will the Reliability Coordinators use consistent criteria for listing sub 200-kV facilities to be included under FAC-003-2? The purpose of FAC-003 is to ensure inter-regional reliability and to focus on the reliable operation of these lines. By leaving the decision up to the individual Reliability Coordinators - there is the potential for local differences in determining which sub-200-kV facilities may be critical. This could result in some transmission owners having to include certain facilities under the requirements of FAC-003-2 where in other regions of the country - similar facilities may not be included by the Reliability Coordinator. Although there have been criteria established to guide the Reliability Coordinators in the determination of sub-200-KV facilities for inclusion under FAC-003-2 - is this sufficient to ensure uniformity throughout the US? Perhaps some involvement at the Regional Entity level at least, is warranted.
Response: Thank you for your comments. The SDT agrees with the points you raise regarding inter-regional reliability. This is addressed in part by the requirement R10 where consultation with neighboring entities is specified. We feel that the requirement R10 ensures that inter-regional coordination is addressed. **In addition several commenters offered sound rationale for replacement of RC with PC. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this.**		
Baltimore Gas & Electric Company	Agree	The documented method to assess the reliability significance of sub-200 kV lines referenced in R10 should be put out for comment by the Reliability Coordinator to the regulated entities and FERC/NERC before it is finalized.
Response: Thank you for your comment. Several commenters offered sound rationale for replacement of RC with PC. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this.		
Entergy Services	Agree	The applicability of this standard should state that it is not applicable to insulated transmission lines, such as underground lines.
Response: Thank you for your comment. The SDT believes that the general term "transmission line" along with the associated tables and terminology sufficiently eliminates any misconception or misdirected thought that this standard applies to underground conductors or other conductors that are insulated in a manner that would prevent their flashover to trees.		
Pepco Holdings, Inc	Agree	FERC Order 693 essentially has the RC replacing the RRO.
Response: Thank you for your comment. Several commenters offered sound rationale for replacement of RC with PC. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this.		
BCTC	Agree	Yes, we agree.

Organization	Agree?	Question 2 Comment
Response: Thank you for your participation.		
Buckeye Power, Inc.	Agree	Agreed on this question.
Response: Thank you for your participation.		
Western Area Power Administration, Rocky Mountain Region	Agree	
Florida Power & Light	Agree	
Bonneville Power Administration	Agree	
FirstEnergy	Agree	
SERC Compliance Staff	Agree	
Exelon	Agree	
Central Maine Power Company	Agree	
City of Tallahassee	Agree	
Northern California Power Agency (NCPA)	Agree	
Northern Indiana Public Service Company	Agree	
Tampa Electric Company	Agree	
Orange and Rockland Utilities	Agree	

Organization	Agree?	Question 2 Comment
Inc.		
Long Island power Authority	Agree	
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	
Consumers Energy Company	Agree	
Pacific Gas & Electric Co.	Agree	
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	
San Diego Gas & Electric	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
Arizona Public Service Co.	Agree	
JEA	Agree	
CenterPoint Energy	Agree	
Salt River Project	Agree	

3. In R1 the proposed standard replaces "prepare, and keep current" with "have", replaces the list of terms, "objectives, practices, approved procedures, and work specifications," with "designed to control vegetation", defines the "active transmission line ROW", and specifies that the transmission vegetation management program applies to that area. Do you agree with R1? If not, please explain.

Summary Consideration:

Regarding the use of "have", some commenters requested that the original wording should remain. However, the SDT and some other commenters note that proving whether something is "current" is an opportunity for compliance ambiguity and unintended discrimination. Therefore, the SDT continues to use "have" in the second draft.

A few commenters raised the issue concerning Critical Clearance Zone in this question and that has been addressed with the substantive changes which have been made to the second draft standard.

While some commenters prefer the list of terms, the SDT chose the term "methods" as a more global, all encompassing term that allows transmission owners flexibility in developing their Transmission Vegetation Management Program. The SDT agrees the list of terms is helpful. However, when listed in a Requirement there is an expectation that all such terms must be included and evidence produced to show compliance. The list of terms can be included in the technical reference to assist Transmission Owners.

Finally, many commenters wanted more specificity in the reference material to describe the "Active Transmission Line Right-of-Way". The SDT has provided additional clarification in the technical reference document.

The revised R1 is shown below:

R1. Each Transmission Owner shall have a documented transmission vegetation management program that describes how it conducts work on its Active Transmission Line Rights of Way to prevent Sustained Outages due to vegetation, considering all possible locations the conductor may occupy under the effects of sag and sway throughout its operating range under rated conditions. The transmission vegetation management program shall:

1.1. Specify the methods that the Transmission Owner may use to control vegetation.

1.2. Specify a Vegetation Inspection frequency of at least once per calendar year that takes into account local[3] and environmental factors.

1.3. Require an annual plan. An annual work plan shall:

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1.3.1 Identify the applicable lines to be maintained

1.3.2 Identify the work to be performed

1.3.3 Be flexible to adjust to changing conditions and to findings from Vegetation Inspections. Adjustments to the plan within the year are permissible.

1.3.4 Take into consideration permitting and scheduling requirements from landowners or regulatory authorities.

1.4. Require a process or procedure for response to an imminent threat of a vegetation related Sustained Outage. The process or procedure shall specify actions which shall include immediate communication of the threat to the responsible control center.

1.5. Specify an interim corrective action process for use when the Transmission Owner is constrained from performing vegetation maintenance as planned.

1.6 Specify the maintenance strategies used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that Table 1 clearances in Attachment 1 are never violated. The maintenance strategies shall consider the sag and sway of the conductor throughout its operating range under rated conditions.

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Organization	Agree?	Question 3 Comment
Bonneville Power Administration	Disagree	R1: BPA understands that version 2 clearly states that the Critical Clearance Zone does not extend beyond the Active Transmission Right of Way. The Technical reference provides examples of active and inactive portions o corridors. BPA feels this list of examples is not exhaustive and therefore the technical reference language shou be changed to read, "Examples of active and inactive portions of corridors include, BUT MAY NOT BE LIMITED Transmission Owner:" Also, since it is clearly stated on page 2 of the Standard, that the Critical Clearance Zone shall not extend beyond the limits of the Active Transmission Line Right of Way, and that these limits are not specifically defined because they may vary by circumstance, the definition of Active Transmission Line Right of Way on Page 2 of the Standard should include a statement that the actual physical limits of each Active Right of Way will be determined by the Transmission Owner. R1.1: BPA recommends retaining the version 1 language of "objectives, practices, approved procedures, and work specifications" as it is more instructive in what is expected of a TMVP then the version 2 replacement language of "methodologies."
Response: Thank you for your comment. The issues concerning Critical Clearance Zone have been addressed by changes which have been made to		

Organization	Agree?	Question 3 Comment
the draft standard. The definition and use of the term "Critical Clearance Zone" have both been removed from the revised standard. **The SDT chose, for the revised standard, the term "methods" as a more global, all encompassing term that allows transmission owners flexibility in developing their Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1.**		
Associated Electric Cooperative Inc.	Disagree	Associated Electric Cooperative Inc agrees with the changes described in Question 3 except for the definition of Active Transmission Line Right of Way. Associated suggests the term be revised to "Active Right-of-Way" for consistency with the present Glossary term "Right-of-Way" and that the definition of Active Right-of-Way be revised to explicitly permit the Transmission Owner to solely determine the appropriate width. A suggested definition is "Active Right-of-Way: The portion of Right-of-Way utilized for active transmission facilities. The width of the Active Right-of-Way, as determined by the Transmission Owner, shall be consistent with the Transmission Owner's normal standards and practices and shall be consistent with good utility practice for other transmission lines of similar voltage and configuration. Inactive or unused portions of the Right-of-Way, intended for future transmission lines or other facilities, may be excluded from the Active Right-of-Way."
Response: Thank you for your comment. While there is logic in your proposal to simply modify Rights-of-Way with "Active", previous commenters wanted to include "Transmission" to clearly eliminate the case of rights-of-way that include lower voltage facilities.		
NPCC	Disagree	While we agree with the suggested changes, we believe that the Transmission Vegetation Management Program should be focused on removal of incompatible vegetation from the Active Right of Way. We recommend using the following phrase in R1: "designed to remove incompatible vegetation on its Active Transmission Lines' Rights 0f Way" instead of "designed to control vegetation on its Active Transmission Lines' Rights of Way ". Incompatible vegetation should be defined as any vegetation which has the potential to grow tall enough to jeopardize the integrity of an applicable transmission line by growing into the Critical Clearance Zone or falling into the Critical Clearance Zone. This would provide clear guidance to all stakeholders, support long term vegetation management philosophies, and complement methods such as IVM where incompatible vegetation is completely removed, and compatible vegetation is encouraged to proliferate, thereby helping to control incompatible vegetation in an environmentally positive manner. Removal of incompatible vegetation is superior to pruning, topping, and trimming in terms of short and long term reliability of the Bulk Electric System. This language would also serve to align NERC and FERC with Transmission Owners who attempt achieve the highest degree of reliability by exercising their full easement rights in cases where strong opposition from landowners and public officials is encountered. If such language is adopted it should apply to R1 and the Transmission Vegetation Management Program. It should be made clear in the technical reference document that removal, rather than pruning of incompatible vegetation is the philosophy that must be incorporated into the Transmission Vegetation Management Program. It

Organization	Agree?	Question 3 Comment
		must be clearly explained that Transmission Owners have the flexibility to perform removals gradually over several treatment cycles in sensitive areas as long as pruning is performed as an interim measure to ensure that Critical Clearance Zone encroachments and on-Right of Way fall overs do not occur. It must also be made clear that the presence of incompatible vegetation on the Right of Way will always occur and does not in itself constitute a violation of the Standard.
Response: Thank you for your comment. The SDT has addressed removal of incompatible vegetation as a best management practice by referencing ANSI A300 as a footnote to Requirement R1. It is noted that A300 is not a requirement of the standard, only a best management practice. We will address your other comments in the technical reference paper for industry guidance.		
Baltimore Gas & Electric Company	Disagree	I agree with the simplification of the language, but I am uncomfortable with the definition of Active Right-of-Way (R/W). The definition in FAC-003-2 and the examples used in the white paper continue to leave room for interpretation, particularly with respect to the example where only one circuit is installed on a double circuit tower. Moreover, there may be circumstances where the Active R/W is relatively narrow and the utility has an Inactive R/W or otherwise owns land adjacent to the Active R/W that can be maintained to protect the facilities from grow-ins. Consequently, consideration should be given to require utilities to protect lines from grow-ins into the Critical Clearance Zone regardless of whether or not the R/W is Active or Inactive as long as the utility has the legal ability to do the necessary work.
Response: Thank you for your comment. The Standard clearly addresses that all grow-ins are considered to be within the active right-of-way, regardless of whether or not the tree is rooted within the active right-of-way. The Standard requires that such vegetation be managed as described in the Transmission Owner's Transmission Vegetation Management Program. Additionally, the SDT has revised the drawings and guidance in the technical reference paper to eliminate the confusion you and others detected.		
Northern Indiana Public Service Company	Disagree	Use of the term "have" is a notable and unnecessary weakening versus the terms "prepare and keep current". One of the key lessons learned from past vegetation related outages and subsequent investigations and reports is that successful UVM programs must continually adapt to changing circumstances which means practices and procedures must be kept current. Why weaken this expectation in the standard? Also, I disagree with the elimination from the revised standard the present requirement R1 that all Transmission Vegetation Management Programs include certain essential components (objectives, practices, approved procedures & work specifications). Why make changes that imply Transmission Vegetation Management Program's without these key components are acceptable?
Response: Thank you for your comment. The SDT believes that the term "have" is appropriate. While sympathetic to your perception about the terms, in order to "have" a Transmission Vegetation Management Program it had to have been prepared. Latency of the plan, like all plans required by NERC standards, can easily be addressed in compliance without creating the task of proving "current" if it is included in the Requirement. The SDT chose, for the revised standard, the term "methods" as a more global, all encompassing term that allows transmission owners flexibility in developing their		

Organization	Agree?	Question 3 Comment
Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1.		
Xcel Energy	Disagree	We propose adding the following language to the end of the definition for "Active Transmission Line Right of Way": OR OTHER PURPOSES, REGARDLESS OF THE PREMISES DIMENSIONS IN ANY EASEMENT, LICENSE AGREEMENT OR OTHER LAND RIGHT DOCUMENT.
Response: Thank you for your comment. The SDT believes that the definition of “active transmission line right-of-way” is appropriate for meeting the objectives of the Standard. This topic will be covered in the technical reference document which will be issued with the next draft of the Standard.		
Hydro One Networks Inc.	Disagree	We agree in changing the text as proposed only if R1 is expanded as suggested below. The standard as written is primarily, if not exclusively focused on outage prevention through one means, to keep vegetation out of the Critical Clearance Zone. The burden to accomplish this is placed on the Transmission Owner/Operator as it should be. The first section highlights that a program is required, but does not provide a requirement above this simplistic view, and from our perspective the Measures do not introduce any further rigour. This simplistic approach, in our opinion, does not adequately address the reliability risks associated with the various methodologies of managing vegetation. The White Paper notes removal is superior to pruning in ensuring tree conflicts do not occur. The White Paper includes elements of vegetation management risks, but the revised standard for the most part excludes this issue. One could argue that the audits and fines will manage reliability risks, but we are not convinced that this will do so in a consistent and adequate manner. There are numerous clearance risk factors associated with managing vegetation on rights of way. Some of these are: accurate measurement of conductor sag, accurate measurement of vegetation, vegetation growth rate, conductor sway, tree movement. If one looks at Table 1, the Clearance Distances are to the nearest cm or 1/100 of a foot. This makes one wonder, how realistic are the expectations laid out in the standard? To manage the risks around the Critical Clearance Zone the Standard requires each Transmission Owner to work with these precise numbers and build in a margin of safety to manage the situation. Will each Transmission Owner use identical criteria to trigger work? This doubtful, so this leads one to believe that the standard has not been designed to produce consistent results, which in our opinion is the case. So one has varied field conditions that are difficult to nail down, precise clearance requirements to the nearest 1/100? and the likelihood of inconsistent margins of safety. We realize that the audit process will help to assess these situations, but it may not be enough to achieve a somewhat uniform risk profile across the transmission systems. Other standards that we are familiar with include a margin of safety such as added clearance above the absolute minimum recognizing that it may not be practical to work to such precise measures. Examples of standards that use this approach to ensure consistent and reliable results include OHSA and the Canadian Standards Association. We are not advocating that this standard follows an identical approach, but do want to highlight that the standard may fall short in the area of managing vegetation management risks which in turn have a direct impact on reliability. Considering the above, it is suggested that the aspect of managing vegetation reliability risks be added to the White Paper to allow Transmission Owners to develop somewhat consistent criteria. Further on the topic of managing risk. We believe that reliability risks are

Organization	Agree?	Question 3 Comment
		directly related to the amount of incompatible vegetation on a right of way that is approaching the Critical Clearance Zone. Incompatible vegetation would be vegetation that has the potential to grow into the Critical Clearance Zone at full growth. We suggest that risks could be reduced significantly by including direction in the standard concerning the management of incompatible vegetation. This would drive a greater degree of consistency among Transmission Owners and would reduce the amount of vegetation on rights of way that have the potential to cause flashover. In addition, this would reinforce the reliability risks associated with vegetation, not just from a clearance perspective but also from a volume perspective, and would provide a more comprehensive view for the public and interest groups. In order to respond to what we consider a shortcoming of the proposed standard, our suggestion would be to expand R1.1 similar to the following: Specify the methodologies that the Transmission Owner uses to control vegetation and demonstrate that the removal of non-compatible vegetation is a focus within the plan. It is recognized that reliability risks increase appreciably with an increase in incompatible vegetation on an active right of way, and the Transmission Owner is required to remove incompatible vegetation at a point no later in time when it poses a threat to the reliability of the transmission line. Exceptions include vegetation used for designated visual screens, trees of a historic significance, vegetation to control erosion, agreements made at the time of environmental approval for construction,???etc.
Response: Thank you for your comments. The SDT revised the standard so that it no longer references the “Critical Clearance Zone.” The SDT chose, in the revised standard, to use the term “methods” as a more global, all encompassing term that allows transmission owners flexibility in developing their Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1. Moreover, we believe the Standard as subsequently revised provides flexibility for Transmission Owners to develop their own vegetation management programs. But we are sensitive to the issues you raised and have tried to define through the subsections in R1 that specific elements are necessary.		
CenterPoint Energy	Disagree	The term "Active Transmission Line Right-of-way" is not defined in sufficient detail in the Definition of Terms Used in the Standard section to know how to apply the Requirements. The term causes a circular reference problem with the term "Critical Clearance Zone" that refers to the "limits of the Active Transmission Line Right-of-way" which has no specific definition as to its limits within the proposed revised Standard. There is an attempt to differentiate between the "Total R.O.W." and the "Active R.O.W." portion by using the phrase "occupied by active transmission facilities", but no specific limits of such occupation are included within the definition. Are "active transmission facilities" only the physical energized conductors as-is, where-is? Does "occupied" include the conductor vertical and horizontal movement envelope and any horizontal and vertical electrical clearance as well? Does the term "Active Transmission Line Right-of-way" refer to the legal limits of the right-of-way? The new R9 includes the phrase "within the extent of its easement and/or legal rights" which seems to support that definition. The phrase "a strip of land" seems to refer to a metes and bounds description, but how is that relevant when no specific land space is defined, such as with a railroad occupation or Corp of Engineer's permit? On page 16 of the Technical Reference, there is a reference to the Bramble and Byrnes wire-border zone technique. The wire zone

Organization	Agree?	Question 3 Comment
		is defined in the Technical Reference as "the section of a utility transmission right-of-way directly under the wires and extending outward about 10 feet on each side". Are the limits of the "Active Transmission Line Right-of-way" intended to be equivalent to the Bramble and Byrnes wire zone, or is the Transmission Owner to use its discretion to define the limits? The examples in the Technical Reference document do not define the limits of the "active transmission facilities" either. The "Active R.O.W." limit in Figure 1 and Figure 3 is arbitrary. Figure 2 is supposed to display an edge zone for vegetation to exist, which implies an "Inactive R.O.W" portion, but no such zone is defined. Figure 1 also has trees shown inside the "Total R.O.W." and within the "Inactive R.O.W." that are tall enough and close enough to be within falling distance of the active transmission line which seems averse to R7 for vegetation falling into a conductor when the Transmission Owner likely has legal rights to remove them if they are within the "Total R.O.W." and are within falling distance. The interpretation of M7 will be difficult in this case without a specific method to define the "Active R.O.W." portion of the Total R.O.W. We recommend deleting the confusing terms "Active Transmission Line Right-of-way and "Critical Clearance Zone" and returning to the prior Clearance 2 Requirement with the newly specified minimum clearances from Table I of Attachment 1 as an alternative approach should the definition of minimum vegetation clearance distances remain integral to the Standard.
Response: Thank you for your comments. The Critical Clearance Zone concept has been removed from the latest draft of the Standard. While the SDT believes that the definition of "active transmission line right-of-way" in the Standard is appropriate, this concept will be further reviewed by the SDT in the context of the technical reference and your comments. And we agree that a further explanation is required to eliminate questions like the ones you raised. The new examples in the technical reference should eliminate that ambiguity.		
JEA	Disagree	The standard should EITHER require an entity to have and follow a program OR hold an entity to performance standards, but not both. Requiring a procedure in conjunction with performance requirements incents the entity to write procedures that meet only the minimum requirements of the standard, as they will be audited and held accountable for what is documented and performance against that. If performance requirements are in place without the concurrent requirement for a procedure, then the entity is incented to develop procedures that meet best practices in order to assure that they will meet or beat the performance standards, because in this scenario, such procedures do not expose the entity to additional compliance risk while enhancing reliability.
Response: Thank you for your comment. The Standard provides the framework for Transmission Owners to develop and implement an effective transmission vegetation management program in support of the main reliability objective: preventing sustained outages of transmission lines that could lead to cascading. During the drafting process, many members of the drafting team asserted that several of the requirements are merely facilitative in nature and would be unnecessary if sustained outages are successfully prevented. Because this standard is relatively new compared to standards that were developed from operating policies that had been followed for decades, there is a sense that the benefits of "defense in depth" (keeping the facilitating requirements) may be warranted until entities have more experience with mandatory vegetation management.		

Organization	Agree?	Question 3 Comment
Salt River Project	Disagree	R1.1 states "Specify the methodologies that the Transmission Owner uses to control vegetation". The word "methodologies" does not adequately replace "objectives, practices, approved procedures, and work specifications". Recommend to keep the original wording.
Response: Thank you for your comments. The SDT chose "methods" in R1 part 1.1 to provide flexibility for Transmission Owners to develop their own vegetation management programs. ANSI A300 has been referenced as a best management practice in a footnote to 1.1. The Technical Reference Document provides examples of the variations in methods that are necessary due to the wide diversity of vegetation across North America.		
Hydro-Quebec Transenergie (HQT)	Disagree	While we agree with the suggested changes for the terms proposed , we believe that the Transmission Vegetation Management Program should be focused on removal of incompatible vegetation from the Active Right of Way.R1.1 could read: Specify the methodologies that the Transmission Owner uses to control vegetation and demonstrate that the removal of non-compatible vegetation is a focus within the plan. Incompatible vegetation should be defined as any vegetation which has the potential to grow tall enough to jeopardize the integrity of an applicable transmission line by growing into the Critical Clearance Zone or falling into the Critical Clearance Zone . This would provide clear guidance to all stakeholders, support long term vegetation management philosophies, and complement methods such as IVM where incompatible vegetation is completely removed, and compatible vegetation is encouraged to proliferate, thereby helping to control incompatible vegetation in an environmentally positive manner.
Response: Thank you for your comments. The SDT has re-written this Requirement to address your concerns in a manner that allows transmission owners flexibility in developing their Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1. Moreover, we believe the Standard as subsequently revised provides flexibility for Transmission Owners to develop their own vegetation management programs.		
Western Area Power Administration, Upper Great Plains Region	Agree	A question that has surfaced during discussions within the industry is "Can the Transmission Owner designate an active R/W width that is less than the easement width even with a single-circuit line with no R/W set aside for vegetation buffer or future development?" OR, does the easement width equate to "Active T-Line ROW" under the situation described above.
Response: Thank you for your comment. The intent of the Standard is that such rights-of-way as identified in your response are considered as "active transmission rights-of-way" in general for their full width. The definition of "active transmission line right-of-way" was developed to recognize that in some cases additional ROW width was secured to allow for buffers and future expansion. This is further described in the technical reference document.		
Western Utility Arborists	Agree	Yes, we agree, subject to the qualification about "active" rights-of-way under Comment #16. Under R1.1, it says "Specify the methodologies that the Transmission Owner uses to control vegetation." The single word "methodologies" does not adequately replace "objectives, practices, approved procedures, and work

Organization	Agree?	Question 3 Comment
		specifications." The Western Utilities recommends keeping the original wording. We would also like to point out that the original intent of the standard was to ensure that utilities had a complete vegetation management program. The new standard is evolving towards an outage control program, and no longer encourages programs or behaviors that would ensure the causes of outages are prevented long before they become a problem. The standard now redirects efforts to avoiding outages instead of managing vegetation.
Response: Thank you for your comments. The SDT has re-written this Requirement to address your concerns in a manner that allows transmission owners flexibility in developing their Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1. Moreover, we believe the Standard as subsequently revised provides flexibility for Transmission Owners to develop their own vegetation management programs. The SDT believes that the latest draft includes Requirements that dictate appropriate behavior in controlling vegetation but also added a strong statement that outages, that could have been prevented, are inconsistent with interconnection reliability and should be violations.		
Southern California Edison Company	Agree	Q3: No Comments.
Response: Thank you for your response.		
FirstEnergy	Agree	The Inactive Right of Way, by definition, should include a strip of trees on each side of the of the right of way that was purchased, but not cleared at the time of construction. This could be a narrow strip ten feet on each side that is intended for future hazard tree removal.
Response: Thank you for your comment. The definition of "Active Transmission Line Right-of-Way" has been modified in the current draft of the Standard. The SDT believes that the definition of "Active Transmission Line Right-of-Way" as currently defined is appropriate. The definition was developed to recognize that in some cases additional ROW width was secured to allow for buffers and future expansion. This is further described in the technical reference document. However, the SDT does not agree that a categorical "set aside" which is not active but can be is appropriate for all Transmission Owners. Rather, some Transmission Owners may want to manage the entire rights-of-way. But flexibility is permitted within the current draft.		
MRO NERC Standards Review Subcommittee	Agree	The MRO agrees but requests further clarification on the definition of the term "Active" in Active Transmission Line R.O.W. For example: A utility has a 150 foot easement for a 230kV line and currently manages 80 feet. First; is it the intent of the standard that the utility manage the entire 150 foot easement? Second; is the entire easement considered the Active Transmission Line R.O.W?
Response: Thank you for your comment. The Transmission Owner is responsible for determining the Active ROW width based upon the definition of "active transmission line right-of-way" included in the Standard. The scenario presented in your comment does not provide enough information for the		

Organization	Agree?	Question 3 Comment
SDT to provide a definitive answer. The definition of "Active Transmission Line Right-of-Way" has been changed in the most current draft. In addition a technical reference document with a more detailed explanation of this topic will be issued with the next draft. These documents should provide clarity. The definition was developed to recognize that in some cases additional ROW width was secured to allow for buffers and future expansion. This is further described in the technical reference document. However, the SDT does not agree that a categorical "set aside" which is not active but can be is appropriate for all Transmission Owners. Rather, some Transmission Owners may want to manage the entire rights-of-way. But flexibility is permitted within the current draft.		
ITC HOLDINGS	Agree	The standard doesn't actually explain or define the Active Transmission Line Right of Way.
Response: Thank you for your comment. A definition of "Active Transmission Line ROW" is included in the Standard. This definition has been modified in the most current draft of the Standard. The technical reference will provide further clarity.		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 3
Response: Thank you for your comment.		
American Electric Power (AEP)	Agree	While Requirement R1 does not actually define "Active Transmission Line Right of Way" (it is defined on page 2 of the Standard), AEP concurs with R1, except as noted below for R1.4.
Response: Thank you for your comment.		
Platte River Power Authority	Agree	The list of terms, "objectives, practices, approved procedures and work specifications," from version 1 provides more clarity that the one word "methodology" and should both be replaced. The newly defined term "active transmission line ROW" provides clarity to the portion of the ROW requiring vegetation management and is a valuable addition to the standard.
Response: Thank you for your comment. The SDT revised R1.1 to allow transmission owners the necessary flexibility in developing their Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1.		
American Transmission Company	Agree	We agree with the idea but the term "active transmission facilities" needs additional clarity. This clarity could be accomplished with a footnote. Proposed Footnote: A transmission facility that contains a transmission line to which FAC-003 is applicable. The proposed footnote aids in the identification of applicable transmission facilities.
Response: Thank you for your comment. Applicable lines are defined in Section 4 of the Standard.		

Organization	Agree?	Question 3 Comment
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	My disagreement with R1
Response: Thank you for your comment; however the SDT does not understand your comment.		
National Grid	Agree	Defining "Active Transmission Line Right-of-Way" solves the Right-of-Way definition problem within the SAR.
Response: Thank you for your comment.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	Yes, we agree, subject to the qualification about “active” rights-of-way under Comment #16. We would also like to point out that the original intent of the standard was to ensure that utilities had a complete vegetation management program. The new standard is evolving towards an outage control program, and no longer encourages programs or behaviors that would ensure the causes of outages are prevented long before they become a problem. Instead, it redirects efforts to avoiding outages instead of managing vegetation. If this is now the preferred approach, the term Transmission Vegetation Management Program is no longer valid and should perhaps be changed to the Transmission Vegetation Outage Prevention Program. Under R1.1, it says “Specify the methodologies that the Transmission Owner uses to control vegetation.” The single word “methodologies” does not adequately replace “objectives, practices, approved procedures, and work specifications.” We recommend that the SDT retain the original wording.
Response: Thank you for your comments. The SDT revised R1.1 to allow transmission owners the necessary flexibility in developing their Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1. The SDT believes that the latest draft includes Requirements that dictate appropriate behavior in controlling vegetation but also added a strong statement that outages, that could have been prevented, are inconsistent with interconnection reliability and should be violations.		
San Diego Gas & Electric	Agree	Yes, we agree, subject to the qualification about "active" rights of way under comment 16. Under R1.1 it says "Specify the methodologies that the Transmission Owner uses to control vegetation." The single word "methodologies" does not adequately replace "objectives, practices, approved procedures, and work specifications." We recommend keeping the original wording.
Response: Thank you for your comment. The SDT revised R1.1 to allow transmission owners the necessary flexibility in developing their Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1.		
Northeast Utilities	Agree	With respect to "active transmission line ROW" the examples provided in the Technical Reference document for FAC-003-2 show that any areas of the easement or fee-owned right-of-way not cleared in accordance with

Organization	Agree?	Question 3 Comment
		company approved design standards will not be considered "active transmission line ROW". Any vegetation contacts resulting from trees that fail in these non-cleared sections ("corridor edge zones") would not constitute a violation of FAC-003-2.The definition of the "active transmission line right-of-way" states that this does not include areas of the easement or fee-owned property that is unused or inactive and intended for other facilities. Does this imply that areas not cleared and not intended for other facilities are part of the active right-of-way? If a company had constructed new lines and allowed for a buffer strip of the easement that was not cleared, but is also not intended for new facilities, and trees are allowed to remain in this strip - that an outage from contact with a tree falling into the lines from this buffer would constitute a violation of R7 as a tree falling from within the active right-of-way? Does this imply that trees in these buffer strips must be removed? This will constitute a very costly and problematic position that will result in extreme adverse public opposition to the required clearing. It is suggested that the clearing limits of any right-way comply with some established standards or codes. A utility should not be allowed to eliminate a large number of vegetation violations by simply decreasing the size or width of the active right-of-way. However, this may also need to be flexible when new lines are constructed when easement widths are limited due to local or state requirements.
Response: Thank you for your comments. The definition of "Active Transmission Line Right-of-Way" has been modified in the current draft of the Standard. The SDT believes that the definition of "Active Transmission Line Right-of-Way" as currently defined is appropriate. The definition was developed to recognize that in some cases additional ROW width was secured to allow for buffers and future expansion. This is further described in the technical reference document. The new section in the technical reference attempts to address these issues.		
Buckeye Power, Inc.	Agree	OK with R1. However, the active transmission line right of way seems to be a reduction in ROW width which would likely decrease reliability during the one moment when we need it most.
Response: Thank you for your comment. The "active transmission line right-of-way" definition has been developed to address rights-of-way obtained for future facilities. It is not intended to diminish the Transmission Owners' responsibility to manage vegetation on a right-of-way which was acquired solely for the purpose of the subject line and is necessary for the reliable operation of the line.		
Great River Energy	Agree	GRE agrees but requests further clarification on the definition of the term "Active" in Active Transmission Line R.O.W. For example: A utility has a 150 foot easement for a 230kV line and currently manages 80 feet. First; is it the intent of the standard that the utility manage the entire 150 foot easement? Second; is the entire easement considered the Active Transmission Line R.O.W?
Response: Thank you for your comment. The Transmission Owner is responsible for determining the Active ROW width based upon the definition of "active transmission line right-of-way" included in the Standard. The scenario presented in your comment does not provide enough information for the SDT to provide a definitive answer. The definition of "Active Transmission Line Right-of-Way" has been changed in the most current draft. In addition a technical reference document with a more detailed explanation of this topic will be issued with the next draft. These documents should provide clarity.		

Organization	Agree?	Question 3 Comment
BCTC	Agree	Yes, we agree, subject to the qualification about "active" rights-of-way under Comment #16. We would also like to point out that the original intent of the standard was to ensure that utilities had a complete vegetation management program. The new standard is evolving towards an outage control program, and no longer encourages programs or behaviours that would ensure the causes of outages are prevented long before they become a problem. Instead, it redirects efforts to avoiding outages instead of managing vegetation. If this is now the preferred approach, the term Transmission Vegetation Management Program is no longer valid and should perhaps be changed to the Transmission Vegetation Outage Prevention Program. Under R1.1, it says "Specify the methodologies that the Transmission Owner uses to control vegetation." The single word "methodologies" does not adequately replace "objectives, practices, approved procedures, and work specifications." BCTC recommends keeping the original wording.
Thank you for your comments. The SDT revised R1.1 to allow transmission owners the necessary flexibility in developing their Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1. The SDT believes that the latest draft includes Requirements that dictate appropriate behavior in controlling vegetation but also added a strong statement that outages, that could have been prevented, are inconsistent with interconnection reliability and should be violations.		
WECC Reliability Coordination	Agree	
SERC Vegetation Management Subcommittee (VMS)	Agree	
Progress Energy Florida	Agree	
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Progress Energy Carolinas	Agree	
SERC OC Standards Review Group	Agree	

Organization	Agree?	Question 3 Comment
Florida Power & Light	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	
SERC Compliance Staff	Agree	
Exelon	Agree	
Central Maine Power Company	Agree	
City of Tallahassee	Agree	
Northern California Power Agency (NCPA)	Agree	
Tampa Electric Company	Agree	
Orange and Rockland Utilities Inc.	Agree	
Ameren	Agree	
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Manitoba Hydro	Agree	

Organization	Agree?	Question 3 Comment
Consumers Energy Company	Agree	
Pacific Gas & Electric Co.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Arizona Public Service Company	Agree	
Duke Energy Corporation	Agree	
Entergy Services	Agree	
Pepco Holdings, Inc	Agree	

4. Documentation and implementation of the transmission vegetation management program which were previously combined in Requirement R1 are now separated in order to apply appropriate VRFs and time horizons. The implementation of some elements has been moved into standalone requirements such as inspection cycles (R3) and annual plan implementation (R9). Do you agree with these revisions and separation? If not, please explain.

Summary Consideration: Most respondents were in favor of separating the documentation from the implementation. A minority of the respondents wanted to keep the two together. The SAR directed the team to bring the standard into conformance with the latest version of the Sanctions Guidelines. Retention of documentation to demonstrate compliance is now addressed, in most cases, solely in the "Data Retention" section of standards and does not need to be covered in requirements. If an entity does not retain data and there is no impact to reliability, then the retention of that data, if needed to demonstrate compliance, is covered under the Data Retention section.

Some respondents advocated modifying the order or sequence of the standard's requirements. The SDT has considered various sequence options and offers a re-sequencing proposal as Question #12 in the second Comment Form.

Organization	Agree?	Question 4 Comment
BCTC		Although it's important to have these two separate aspects – documentation and implementation – separating them spatially in the document itself makes the standard longer than necessary and creates redundancy. It seems obvious that if you prepare elements of the Transmission Vegetation Management Program, they also need to be implemented. The document would be easier to follow if the two elements were kept together.
Response: The SDT thanks you for your comments. The SDT determined that the requirements to document and implement are distinctly different activities and therefore separated them. Having separate requirements allows for assignment of VRF's and VSL's that more closely reflect their respective characteristics. The SDT has considered various sequence options and offers a re-sequencing proposal as Question #12 in the second Comment Form.		
Western Utility Arborists		Although it's important to have these two separate aspects "documentation and implementation "separating them spatially in the document itself makes the standard longer than necessary and creates redundancy. It seems obvious that if you prepare elements of the Transmission Vegetation Management Program, they also need to be implemented. The document would be easier to follow if the two elements were kept together.
Response: The SDT thanks you for your comments. The SDT determined that the requirements to document and implement are distinctly different activities and therefore separated them. Having separate requirements allows for assignment of VRF's and VSL's that more closely reflect their respective characteristics. The SDT have considered various sequence options and offer a re-sequencing proposal as Question #12 in the second		

Organization	Agree?	Question 4 Comment
Comment Form.		
Progress Energy Florida	Disagree	The sub-requirements should be moved up to requirement level if the team desires to have different VRFs and VSLs.
Response: The SDT thanks you for your comments. The Standards drafting team has dropped the sub requirement designations and the sub parts are simply listed as part of R1.		
Progress Energy Carolinas	Disagree	The sub-requirements should be moved up to requirement level if the team desires to have different VRFs and VSLs.
Response: The SDT thanks you for your comments. The Standards drafting team has dropped the sub requirement designations and the sub parts are simply listed as part of R1.		
Southern California Edison Company	Disagree	Q4: SCE does not agree with separating the documentation and implementation aspects of the Transmission Vegetation Management Program into separate requirements R3 and R9 (respectively). SCE believes that proposed R3 and corresponding M3 should be eliminated and replaced with a modified version of proposed R9. SCE respectfully suggests that proposed R9 be revised to read: "Each Transmission Owner shall implement and follow its Vegetation Management Program to the extent allowed by existing easement and/or legal rights."
Response: The SDT thanks you for your comments. The team believes that conducting inspections is independently important and therefore should be addressed in a separate requirement. The SDT debated the issue of whether to include "Each Transmission Owner shall implement and follow its Vegetation Management Program to the extent allowed by existing easement and/or legal rights". The final consensus of the SDT was to exclude the requirement because having the legal rights do not imply one is obligated to exercise those rights to their fullest extent. The SDT did not want to give that impression.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Disagree	Although it’s important to have these two separate aspects “ documentation and implementation “ separating them spatially in the document itself makes the standard longer than necessary and creates redundancy. It seems obvious that if you prepare elements of the Transmission Vegetation Management Program, they also need to be implemented. The document would be easier to follow if the two elements were kept together.
Response: The SDT thanks you for your comments. The SDT determined that the requirements to document and implement are distinctly different activities and therefore separated them. Having separate requirements allows for assignment of VRF’s and VSL’s that more closely reflect their respective characteristics. The SDT have considered various sequence options and offer a re-sequencing proposal as Question #12 in the second Comment Form.		

Organization	Agree?	Question 4 Comment
San Diego Gas & Electric	Disagree	The document would be easier to follow if kept together. Separation of the recommendations and implementation will make this a redundant process, because both will say the same thing.
Response: The SDT thanks you for your comments. The SDT determined that the requirements to document and implement are distinctly different activities and therefore separated them. Having separate requirements allows for assignment of VRF's and VSL's that more closely reflect their respective characteristics. The SDT considered other sequence options and offer a re-sequencing proposal as Question #12 in the second Comment Form.		
JEA	Disagree	See comment from #3.
Response: The SDT thanks you for your comments. See response to Q #3.		
Salt River Project	Disagree	Although we agree that it is important to identify both aspects of the program for "prepare/documentation" and "implementation", we do not agree that this needs to be documented in separate requirements. It makes the standard longer than necessary and creates redundancy. The document would be easier to follow if the two elements were kept together in the same requirement. In addition, it is not defined what is "VRFs". We understand that this was detailed in a previous draft document as "Violation Risk Factor". This needs to be defined and clarified in order to provide comment back.
Response: The SDT thanks you for your comments. The SDT determined that the requirements to document and implement are separate and require different levels of VRF's and VSL's. The team refers you to the *Sanction Guidelines of North American Electric Reliability Corporation* to explain the use of VRF's and VSL's.		
CenterPoint Energy	Disagree	Additional revisions are needed to clarify the requirements. For instance, R1.3 refers to "the objectives" of the Transmission Vegetation Management Program, which are no longer a required element and are not specified in M1.3. Reference to "the objectives" should be deleted. The last sentence of R1.3 should read: "It shall use the methodologies outlined in the transmission vegetation management program."R1.4 requires a process for a response to an "imminent threat of a vegetation related Sustained Outage", but R2 refers to implementing an "imminent threat procedure" to "prevent an encroachment of the Critical Clearance Zone". The requirement and the implementation should both refer to an "imminent threat of a vegetation related Sustained Outage".
Response: The SDT thanks you for your comments. The team is posting a revised standard and R1 identifies the required elements of the Transmission Vegetation Management Program. The sub requirements have been changed to elements that roll up into R1 and an additional element has been added to cover methods used to control vegetation – the word, "objectives" is not used in the revised standard.		
MRO NERC Standards Review	Agree	The MRO believes that clarity was improved by separating documentation and implementation. The MRO

Organization	Agree?	Question 4 Comment
Subcommittee		suggests that moving the requirement for implementation so that it immediately follows the requirement for documentation will further enhance clarity.
Response: The SDT thanks you for your comments. The SDT has considered various sequence options and offers a re-sequencing proposal as Question #12 in the second Comment Form.		
Midwest ISO Stakeholders Standards Collaborators	Agree	This is a good change from a compliance perspective; the documentation requirements can now be assigned lower VRFs than the implementation requirements.
Response: The SDT thanks you for your comments.		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 4
Response: The SDT thanks you for your comments.		
Exelon	Agree	Refer to footnotes in R1.1 and 1.2. Are applicable entities to be held accountable to ANSI A300 (footnote 2) and for providing documentation to support analysis that "local factors" were accounted for (footnote 3)? These footnotes should be requirements or they should be removed and included in a Reference Document not subject to compliance audit.
Response: The SDT thanks you for your comments. Please note the phrase in the current version of footnote 2," while not a requirement of this standard." A300 is a recommended best practice and not a requirement. Footnotes may be used to provide explanatory information.		
American Electric Power (AEP)	Agree	AEP agrees with these changes from Version 1.
Response: The SDT thanks you for your comments.		
Platte River Power Authority	Agree	The separation allows lower sanctions and penalties to be assessed for weak documentation and higher sanctions and penalties to be assessed for weak inspection programs and weak vegetation management. However, the standard would be easier to follow if the two elements were kept together in the document.
Response: The SDT thanks you for your comments. The SDT determined that the requirements to document and implement are separate and require different levels of VRF's and VSL's. The SDT has considered various sequence options and offers a re-sequencing proposal as Question #12 in the second Comment Form.		
City of Tallahassee	Agree	See Question 6 and 17.

Organization	Agree?	Question 4 Comment
Response: The SDT thanks you for your comments. See the responses to Questions 6 and 17.		
Northern Indiana Public Service Company	Agree	I agree with the separation and re-ordering of documentation and implementation requirements into two distinct groups. This is a welcome improvement to the standard.
Response: The SDT thanks you for your comments. The SDT has considered various sequence options and offers a re-sequencing proposal as Question #12 in the second Comment Form.		
National Grid	Agree	These revisions and separation make it easier to match requirements and measures.
Response: The SDT thanks you for your comments.		
Ameren	Agree	This is a good change from a compliance perspective; the documentation requirements can now be assigned lower VRFs than the implementation requirements
Response: The SDT thanks you for your comments.		
Duke Energy Corporation	Agree	This is a good change from a compliance perspective; the documentation requirements can now be assigned lower VRFs than the implementation requirements.
Response: The SDT thanks you for your comments		
Great River Energy	Agree	GRE believes that clarity was improved by separating documentation and implementation. GRE suggests that moving the requirement for implementation so that it immediately follows the requirement for documentation will further enhance clarity
Response: The SDT thanks you for your comments. The SDT has considered various sequence options and offers a re-sequencing proposal as Question #12 in the second Comment Form.		
Associated Electric Cooperative Inc.	Agree	
NPCC	Agree	
WECC Reliability Coordination	Agree	

Organization	Agree?	Question 4 Comment
Western Area Power Administration, Upper Great Plains Region	Agree	
SERC Vegetation Management Subcommittee (VMS)	Agree	
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
SERC OC Standards Review Group	Agree	
Florida Power & Light	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
Bonneville Power Administration	Agree	
FirstEnergy	Agree	
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	
Central Maine Power Company	Agree	
Northern California Power Agency	Agree	

Organization	Agree?	Question 4 Comment
(NCPA)		
Tampa Electric Company	Agree	
Orange and Rockland Utilities Inc.	Agree	
American Transmission Company	Agree	
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	
Manitoba Hydro	Agree	
Consumers Energy Company	Agree	
Pacific Gas & Electric Co.	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Arizona Public Service Company	Agree	
Baltimore Gas & Electric Company	Agree	

Organization	Agree?	Question 4 Comment
Entergy Services	Agree	
Pepco Holdings, Inc	Agree	
Independent Electricity System Operator	Agree	
Northeast Utilities	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
Buckeye Power, Inc.	Agree	

5. In R1.2 the Transmission Owner is required to have an inspection frequency of at least once per calendar year. Do you agree with R1.2? If not, please explain.

Summary Consideration: The majority of the respondents were in favor of the one year frequency. Most of the minority commenters wanted to leave the decision with the Transmission Owner. Since vegetation inspections can be included in overhead maintenance inspections, the SDT did not consider the annual inspection requirement to be burdensome. Several commenters asked for a definition of "inspection" and the SDT is proposing the following modification to an existing NERC Glossary definition of "Vegetation Inspection:"

Vegetation Inspection: The systematic examination of vegetation conditions on an Active Transmission Line Right of Way. This inspection may be combined with a general line inspection. The inspection includes the documentation of any vegetation that may pose a threat to reliability prior to the next planned inspection or maintenance work, considering the current location of the conductor and other possible locations of the conductor due to sag and sway for rated conditions.

Organization	Agree?	Question 5 Comment
BCTC		Clarification is required on exactly what an inspection is, which should perhaps be outlined in the white paper. At BCTC although all lines are currently inspected at least once every year the thoroughness of the inspection will vary with the local conditions. Some areas with limited vegetation management issues only require a patrol from the air and are often inspected as part of a routine line patrol, where the lineman looks for vegetation concerns in addition to undertaking maintenance work. Other areas require a detailed ground inspection. BCTC needs some assurance that this inspection will not constitute a dedicated, comprehensive vegetation management inspection of the entire operating system. . Therefore, BCTC needs the ability within the Transmission Vegetation Management Program to define what an inspection is in the context of our utility operations.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections. The SDT revised the NERC glossary term Vegetation Inspection to allow it to be combined with other line inspections.		
Western Utility Arborists		Clarification is required on exactly what an inspection is, which should perhaps be outlined in the white paper. There are areas where inspections are not necessary at all, such as lines over a parking lot, or in a remote desert area. The Western Utilities need some assurance that this inspection will not constitute a dedicated, comprehensive vegetation management inspection. Inspections are currently often part of a routine line patrol, where the lineman looks for

Organization	Agree?	Question 5 Comment
		vegetation concerns in addition to undertaking maintenance work. Therefore, the Transmission Owner needs the ability within their Transmission Vegetation Management Program to define what an inspection is in the context of their utility operations.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections. The SDT revised the NERC glossary term Vegetation Inspection to allow it to be combined with other line inspections.		
Associated Electric Cooperative Inc.	Disagree	While Associated Electric Cooperative Inc agrees with this requirement in general, there may be areas (e.g. highly arid terrain, open water, etc.) where an annual interval is unnecessary and adds little or nothing to reliability.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		
NPCC	Disagree	There were differing opinions within the group. Those entities with extensive overhead transmission felt the once a year requirement was overly prescriptive and would not improve reliability, others were in agreement with the "at least once per calendar year" requirement.
Response: The SDT thanks you for your comments. The consensus of the SDT is that annual inspections add to the reliability of the system.		
Tennessee Valley Authority	Disagree	TVA suggests that R1.2 be changed by adding "except in cases where lines or significant sections of lines are over terrain which is void of vegetation(such as bodies of deep water)or over terrain void of any vegetation that can grow to a mature height that could threaten the conductors, then longer cycles will be acceptable". This would avoid unnecessary expenses in such cases.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		
Western Area Power Administration, Rocky Mountain Region	Disagree	Some areas such as highly developed urban areas, deserts, or grassland prairie may not be conducive to tall vegetation growth and require frequent (annual) inspection.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		

Organization	Agree?	Question 5 Comment
Southern California Edison Company	Disagree	Q5: SCE does not agree with imposing a one-size-fits-all inspection frequency of ?at least once per calendar year? upon all U.S. Transmission Owners. The associated technical paper presents no credible evidence or statistical corroboration to support the proposed inspection frequency. Until such time as a thorough industry study or similar evidence is presented that demonstrates the proposed inspection frequency is cost effective and will enhance system reliability, Transmission Owners should be allowed to establish their own inspection frequency rate. Regarding the enforcement of a non-standardized inspection frequency, should a Transmission Owner incur a vegetation-to-line contact that results in a Sustained Outage, upon review of the investigation results, the responsible Reliability Coordinator and/or NERC could then impose a more stringent inspection frequency requirement upon the infracting Transmission Owner. The imposition of more stringent inspection frequencies could be applied on a temporary or permanent basis, depending on the severity of the outage, but lacking a demonstrated need, good performing Transmission Owners should be allowed to establish their own inspection frequencies based upon their individual needs and operating conditions. SCE respectfully suggests R1.2 be revised to read: "Specify a vegetation inspection frequency that takes into account local and environmental factors."
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		
SERC OC Standards Review Group	Disagree	While the SERC OCSRG agrees with this requirement in general, there may be areas (e.g., desert terrain) where an annual interval would be unnecessary and not cost effective.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		
City of Tallahassee	Disagree	While TAL's specific conditions and current process would meet this requirement, I can envision where some conditions may not require an annual inspection. These might include desert conditions, crop fields, over water, etc. To dictate a specific one-year requirement could be burdensome to some utilities with no improvement to the reliability of the BES.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		
Xcel Energy	Disagree	Add a note of exception to the requirement for inspections on those lines that do not have vegetation management issues (e.g. lines that traverse desert areas only).
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done		

Organization	Agree?	Question 5 Comment
annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Disagree	It would seem also that the T.O. should be expected to react to circumstances that create the need for a more frequent inspection cycle such as conditions that cause widespread vegetation mortality such as drought and/or beetle infestations.
Response: The SDT thanks you for your comments. The standard does restrict the number of inspections and does require the Transmission Owner to examine the local and environmental conditions that might require a greater frequency.		
Consumers Energy Company	Disagree	FERC required NERC in Order 693 to develop appropriate inspection cycles based on local factors. Potential annual tree growth varies considerably within the geography of the United States and FAC-003-1 recognized this factor and left it up to the utility to determine the most appropriate inspection cycle for their system. This was in lieu of having proper data readily available to determine inspection cycles for various areas that could be incorporated into the standard. FAC-003-2 greatly decreases the minimum separation distance between conductors and vegetation. Table 1 shows the minimum distance at sea level for a 345 kV line a 3.12 feet. This is considerably less than the potential annual growth rate of many tree species in many areas of the United States. Therefore, the annual inspection cycle would not be acceptable to identify tree growth that can violate the minimum distance before it occurs. Consumers Energy strongly believes that using the Gallet formula to determine the minimum clearance between conductors and vegetation will decrease the reliability of the system compared to the minimum clearance requirements in FAC-003-1.
Response: The SDT thanks you for your comments. The consensus of the SDT is that the frequency of inspection does not drive the minimum clearance the Transmission Owner operates from. The SDT would expect the minimum clearance to be driven by growth rate and maintenance frequency.		
National Grid	Disagree	R1.2, M1.2 and M1.3 in the Standard all refer to calendar year. National Grid objects to inspections being based on a calendar year. Transmission Owners should be able to define their own "year". (See Question No. 18.)
Response: The SDT thanks you for your comments. By using “once per calendar year” the standard does not confine the inspection to a specific date. This improves flexibility in the inspection schedule.		
Hydro One Networks Inc.	Disagree	Clarification is required on the requirements. The frequency and need for inspection is based on a number of factors that include: type of vegetation on a right of way, change in growing conditions and the Transmission Owner’s clearance standards (i.e., if the clearance standards are well above the Critical Clearance then the risk to reliability may be very low, so why inspect for vegetation clearances on an annual basis?) This being the case, clarification is needed on inspection requirements relative to the overall approach used to manage vegetation clearances. For example, Hydro One conducts routine line inspections on an annual basis and identifies clearance issues. Would this

Organization	Agree?	Question 5 Comment
		meet the requirements of the standard?
Response: The SDT thanks you for your comments. Yes. The SDT added a definition for Vegetation Inspection to the standard.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Disagree	Clarification is required on exactly what an inspection is, which should perhaps be outlined in the white paper. There are areas where inspections are not necessary at all, such as lines over a parking lot, or in a remote desert area. We need some assurance that this inspection will not constitute a dedicated, comprehensive vegetation management inspection. Inspections are currently often part of a routine line patrol, where the lineman looks for vegetation concerns in addition to undertaking maintenance work. Therefore, the Transmission Owner needs the ability within their Transmission Vegetation Management Program to define what an inspection is in the context of their utility operations.
Response: The SDT thanks you for your comments. The SDT added a definition for Vegetation Inspection to the standard.		
CenterPoint Energy	Disagree	The Standard and the Technical Reference provide no specific justification for defining a 1-year inspection frequency and is arbitrary. The requirement itself does not take into account "local and environmental factors". Since the type of inspection is not specified within the Standard, a frequency of at least once per calendar year is currently workable for CenterPoint Energy, but it may not necessarily be appropriate for Transmission Owners with sparsely vegetated service territories. The Technical Reference for R1.2 should state, "the Transmission Owner is given discretion as to the inspection method", and "that while the inspection frequency is specified, it is not the intent of the Standard that all vegetation be maintained on the same frequency". For example, CenterPoint Energy currently utilizes a 5-year ground-based inspection cycle coupled with a 5-year cycle for vegetation maintenance, and performs a supplemental annual aerial inspection.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations and this is explained in the Technical Reference. Vegetation inspections can be included in overhead maintenance inspections. The SDT added a definition for Vegetation Inspection to the standard which would work provided you do your annual flight.		
Alberta Electric System Operator	Disagree	The AESO believes that the inspection schedule should consider local and environmental factors that may impact the anticipated growth rate of vegetation. In many of the areas in Alberta, due to cold climate and arid conditions, we have slow vegetation growth rates. The requirement for minimum annual inspection is not necessary. We recommend the inspection schedule be determined by the Transmission Owner and documented in its vegetation management plan.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done at		

Organization	Agree?	Question 5 Comment
least annually to cover both engineering and vegetation situations. A more frequent cycle may specified by the Transmission Owner to account for local conditions. Slow growth rates, arid conditions etc. which may render an annual frequency unnecessary for Vegetation Inspections can be included in overhead maintenance inspections.		
Pepco Holdings, Inc	Disagree	While an annual inspection is reasonable and appropriate for all but very low precipitation areas, In Order 693, the Commission directs the ERO to develop compliance audit procedures, using relevant industry experts, which would identify appropriate inspection cycles based on local factors. The SDT does not seem to have taken the local factors into account. FERC also does not want to leave this up to the Transmission Owners. While the standards being developed are moving many things to the RC, PHI sees that as the only way to have someone other than the Transmission Owner determine an inspection cycle that would consider local factors.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done at least annually to cover both engineering and vegetation situations. A more frequent cycle may specified by the Transmission Owner to account for local conditions. Slow growth rates, arid conditions etc. which may render an annual frequency unnecessary for Vegetation Inspections can be included in overhead maintenance inspections.		
Hydro-Quebec Transenergie (HQT)	Disagree	The frequency and need for inspection is based on a number of factors that include: type of vegetation on a right of way, rainfall during any given year, climate (very slow growth in nordic area), when the last removal of vegetation was done, etc. HQT believes R1.2 is overly prescriptive when a “at least once a year” becomes mandatory; these terms should be removed from the Standard.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done at least annually to cover both engineering and vegetation situations. A more frequent cycle may specified by the Transmission Owner to account for local conditions. Slow growth rates, arid conditions etc. which may render an annual frequency unnecessary for Vegetation Inspections can be included in overhead maintenance inspections.		
Bonneville Power Administration	Agree	It would be helpful to clarify what is expected in regards to what constitutes an inspection. This could be done in the technical reference. Some Transmission Operators inspect vegetation as part of line patrol that focuses on more than just the condition of vegetation along the Right of Way. It should be clear that the Transmission Owner, though required to complete a inspection frequency of at least once per calendar year, has the ability to implement the type of inspection it deems necessary. Also the frequency of once per calendar year may create some unintended reporting difficulties if Transmission Owners currently track progress and completion of inspections using a different convention than calendar year, e.g., fiscal year or other period. It may be helpful to change the wording of R1.2 from "at least once per calendar year" to "once in a twelve month period."
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done		

Organization	Agree?	Question 5 Comment
annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		
MRO NERC Standards Review Subcommittee	Agree	The MRO suggests rewording the requirement to remove ". and environmental" . The MRO believes that local factors includes environmental.
Response: The SDT thanks you for your comments. The SDT considers local conditions to account for design and operating situation and environmental includes both the normal expected environmental conditions and changes from the norm such as drought major storms, fire etc.		
SERC Vegetation Management Subcommittee (VMS)	Agree	While the SERC VMS agrees in general, there may be areas (i.e. desert terrain) where an annual interval would be unnecessary and not cost effective.
Response: The SDT thanks you for your comments. The consensus of the SDT is that annual inspections add to the reliability of the system.		
American Electric Power (AEP)	Agree	AEP agrees with this change.
Response: The SDT thanks you for your comments.		
Platte River Power Authority	Agree	The inspection frequency is reasonable.
Response: The SDT thanks you for your comments.		
American Transmission Company	Agree	We agree with a minimum inspection frequency, but believe that the additional verbiage "? that takes into account local and environmental factors" should be deleted. The additional verbiage does not provide greater reliability only more documentation. Proposed Language: Specify a vegetation inspection frequency of at least once per calendar year.
Response: The SDT thanks you for your comments. The consensus of the SDT is that local and environmental factors might demand a greater frequency than once per calendar year and vegetation inspections can be included in overhead maintenance.		
Arizona Public Service Company	Agree	Clarification is required on exactly what an inspection is, which should perhaps be outlined in the white paper. There are areas where inspections are not necessary at all, such as lines over a parking lot, or in a remote desert area. APS needs some assurance that this inspection will not constitute a dedicated, comprehensive vegetation management inspection. Inspections are currently often part of a routine line patrol, where the forester or lineman looks for vegetation concerns in addition to undertaking maintenance work. Therefore, the Transmission Owner needs the

Organization	Agree?	Question 5 Comment
		ability within their Transmission Vegetation Management Program to define what an inspection is in the context of their utility operations.
Response: The SDT thanks you for your comments. The SDT added a definition for Vegetation Inspection to the standard.		
Pacific Gas & Electric Co.	Agree	This requirement is appropriate to ensure adequate inspection frequencies, however, a clear definition of "inspection" should be contained in either the standard or white paper.
Response: The SDT thanks you for your comments. The SDT added a definition for Vegetation Inspection to the standard.		
JEA	Agree	Although there are probably few areas where this is appropriate, the entity should be able to reduce the required number of inspections with RC approval if they are able to demonstrate that vegetation conditions surrounding transmission lines does not warrant inspections at that frequency.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		
Salt River Project	Agree	The Transmission owner needs the ability to define what an inspection is in the context of their utility operation. Inspections may not constitute a dedicated, comprehensive vegetation management inspection, but could often be part of a routine line patrol, where linemen or engineers look for vegetation concerns in addition to undertaking maintenance work. Clarification of that would be helpful, suggest that could be documented in the Technical Reference document.
Response: The SDT thanks you for your comments. The SDT added a definition for Vegetation Inspection to the standard.		
Great River Energy	Agree	GRE suggests rewording the requirement to remove ". and environmental" . GRE believes that local factors takes into account environmental.
Response: The SDT thanks you for your comments. The SDT considers local conditions to account for design and operating situation and environmental includes both the normal expected environmental conditions and changes from the norm such as drought major storms, fire etc.		
San Diego Gas & Electric	Agree	The term "inspection" needs to be better defined, as well as the term "calendar year."

Organization	Agree?	Question 5 Comment
Progress Energy Carolinas	Agree	
Florida Power & Light	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
Progress Energy Florida	Agree	
Kansas City Power & Light	Agree	
E.ON U.S.	Agree	
FirstEnergy	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	
Exelon	Agree	
Central Maine Power Company	Agree	

Organization	Agree?	Question 5 Comment
Northern California Power Agency (NCPA)	Agree	
Northern Indiana Public Service Company	Agree	
Tampa Electric Company	Agree	
Orange and Rockland Utilities Inc.	Agree	
Ameren	Agree	
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Manitoba Hydro	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Baltimore Gas & Electric Company	Agree	
Duke Energy Corporation	Agree	
Entergy Services	Agree	

Organization	Agree?	Question 5 Comment
Independent Electricity System Operator	Agree	
Northeast Utilities	Agree	
Buckeye Power, Inc.	Agree	

6. **In R1.3 the Standard requires that transmission vegetation management program specify an Annual Plan and specifies parameters for the plan. Implementation of the Annual Plan is separated and placed in R9. Do you agree with R1.3 and the separation of the implementation from the specification of the Annual Plan? If not, please explain.**

Summary Consideration: The majority of the respondents are in favor of the changes. There was a minority of the respondents that made a valid point that elements in the annual plan were lost in the posting. The SDT determined that the requirement to document and implement are separate and require different levels of VRF's and VSL's. The SDT chose a compromise wording to accommodate those points.

Organization	Agree?	Question 6 Comment
BCTC		The document would benefit from keeping the two requirements together, since they relate to the same topic. Under the new wording in R1, the Transmission Vegetation Management Program no longer has a requirement to include objectives. However, there is a phrase in R1.3 to "support the objectives…and methodologies…outlined in the…program." To be consistent with R1.3, BCTC recommends that R1.1 be reworded to specify the methodologies and objectives that the Transmission Owner uses to control vegetation.
Response: The SDT thanks you for your comments. However, the SDT determined that the requirements to document and implement should be separate and require different levels of Violation Risk Factors and Violation Severity Levels. Thus, the SDT respectfully does not adopt your suggestion to keep the two requirements together. The SDT also disagrees with returning "objectives" to R1. We do, however, agree that there exists a small dichotomy since "objectives" are no longer stated in R1 while being referenced in part 1.3. Subsequently the SDT has removed this wording from part 1.3. Further, the SDT has revised R1 to require the Transmission Owner to specifically describe how it will conduct work to comply with the Standard in lieu of requiring the Transmission Owner to only identify general objectives.		
Western Utility Arborists		The document would benefit from keeping the two requirements together, since they relate to the same topic. Under the new wording in R1, the Transmission Vegetation Management Program no longer has a requirement to include objectives. However, there is a phrase in R1.3 to "support the objectives" and methodologies "outlined in the "program." To be consistent with R1.3, the Western Utilities recommends that R1.1 be reworded to specify the methodologies and objectives that the Transmission Owner uses to control vegetation.
Response: The SDT thanks you for your comments. However, the SDT determined that the requirements to document and implement should be separate and require different levels of Violation Risk Factors and Violation Severity Levels. Thus, the SDT respectfully does not adopt your suggestion to keep the two requirements together. The SDT also disagrees with returning "objectives" to R1. We do, however, agree that there exists a small dichotomy since "objectives" are no longer stated in R1 while being referenced in part 1.3. Subsequently the SDT has removed this wording from part 1.3. Further, the SDT has revised R1 to require the Transmission Owner to specifically describe how it will conduct work to comply with the		

Organization	Agree?	Question 6 Comment
Standard in lieu of requiring the Transmission Owner to only identify general objectives.		
NPCC	Disagree	R1.2 and R1.3 should specifically state calendar year, and the Annual Plan and inspection follow the same calendar year timing.
Response: The SDT thanks you for your comments. The SDT points out that these two parts, R1.2 and R1.3, refer to different aspects of the Transmission Vegetation Management Program. Further, to assist in clarity, the SDT has revised part 1.3 and in doing so has removed the phrase "during the year" since it added no value to the requirement. The SDT does not agree with your suggestion to base the annual plan on a calendar year and feels that the Transmission Owner should retain the flexibility to determine the time period for - Requirement R1 clearly limits the scope of the TVMP to work on the entity's Active Transmission Line Rights of Way - and the "annual work plan" is one element of the overall TVMP annual plan.		
City of Tallahassee	Disagree	While I can agree with a separate requirement (R9) to implement the plan developed in R1.3, they need to both have the flexibility desired in R1.3. I do not see that flexibility in R9. See response to question 17.
Response: The SDT thanks you for your comments. R9 is the implementation of 1.3 which is flexible. The flexibility of 1.3 carries through to R9.		
Northern Indiana Public Service Company	Disagree	I disagree with the elimination of the present requirement R2 (last sentence) that requires a Transmission Owner to have proper quality control (QC) systems and procedures in place to document & track planned UVM work so as to verify it was completed properly to work specifications. The need for this requirement was demonstrated as recently as last year when a grow-in outage occurred at BG&E due to a contractor trimming the wrong tree at the wrong location, a situation that could have been prevented with effective QC.
Response: The SDT thanks you for your comments. The consensus of the SDT is that in order to implement the plan the Transmission Owner must complete its work plan to its standards. The level of QC is within the Transmission Owner's purview.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Disagree	I think that the Transmission Owner should be able to specify the effective period of the plan whether it is one year or ten years. Arizona utilities are starting to think in terms of multi-year corridor management plans. A one year planning period could be specified as the minimum planning period.
Response: The SDT thanks you for your comments. The SDT agrees that long term plans can be of value and can be done within the standard. The standard is trying to insure the immediate reliability work is budgeted and completed.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Disagree	The document would benefit from keeping the two requirements together, since they relate to the same topic. Under the new wording in R1, the Transmission Vegetation Management Program no longer has a requirement to include objectives. However, there is a phrase in R1.3 to "support the objectives" and methodologies" outlined in the "program." To be consistent with R1.3, we recommend that R1.1 be reworded to specify the methodologies and

Organization	Agree?	Question 6 Comment
		objectives that the Transmission Owner uses to control vegetation.
Response: The SDT thanks you for your comments. However, the SDT determined that the requirements to document and implement should be separate and require different levels of Violation Risk Factors and Violation Severity Levels. Thus, the SDT respectfully does not adopt your suggestion to keep the two requirements together. The SDT also disagrees with returning "objectives" to R1. We do, however, agree that there exists a small dichotomy since "objectives" are no longer stated in R1 while being referenced in part 1.3. Subsequently the SDT has removed this wording from part 1.3. Further, the SDT has revised R1 to require the Transmission Owner to specifically describe how it will conduct work to comply with the Standard in lieu of requiring the Transmission Owner to only identify general objectives.		
Arizona Public Service Company	Disagree	The document would benefit from keeping the two requirements together, since they relate to the same topic. Under the new wording in R1, the Transmission Vegetation Management Program no longer has a requirement to include objectives. However, there is a phrase in R1.3 to "support the objectives" and methodologies "outlined in the "program." To be consistent with R1.3, APS recommends that R1.1 be reworded to specify the methodologies and objectives that the Transmission Owner uses to control vegetation.
Response: The SDT thanks you for your comments. However, the SDT determined that the requirements to document and implement should be separate and require different levels of Violation Risk Factors and Violation Severity Levels. Thus, the SDT respectfully does not adopt your suggestion to keep the two requirements together. The SDT also disagrees with returning "objectives" to R1. We do, however, agree that there exists a small dichotomy since "objectives" are no longer stated in R1 while being referenced in part 1.3. Subsequently the SDT has removed this wording from part 1.3. Further, the SDT has revised R1 to require the Transmission Owner to specifically describe how it will conduct work to comply with the Standard in lieu of requiring the Transmission Owner to only identify general objectives.		
Baltimore Gas & Electric Company	Disagree	See response to question no. 17.
Response: The SDT thanks you for your comments. See response to comments on #17.		
JEA	Disagree	See comment from #3.
Response: The SDT thanks you for your comments. See response to comments on #3.		
Salt River Project	Disagree	The document would be easier to follow if the two elements were kept together in the same requirement (similar to comments stated in Comment #4 above). It makes the standard longer than necessary and creates redundancy. Also, under the new wording in R1, the Transmission Vegetation Management Program no longer has a requirement to include objectives. However, there is a phrase in R1.3 to "support the objectives" and methodologies "outlined in the..program". To be consistent with R1.3, it is recommended that R1.1 be reworded to

<table>
<tr><th>Organization</th><th>Agree?</th><th>Question 6 Comment</th></tr>
<tr><td></td><td></td><td>specify the methodologies and objectives that the Transmission Owner uses to control vegetation.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comments. However, the SDT determined that the requirements to document and implement should be separate and require different levels of Violation Risk Factors and Violation Severity Levels. Thus the SDT respectfully does not adopt your suggestion to keep the two requirements together. The SDT also disagrees with returning “objectives” to R1. We do, however, agree that there is a small dichotomy since “objectives” are no longer stated in R1, while being referenced in part 1.3. Subsequently, the SDT has removed this wording from part 1.3 Further, the SDT has revised R1 to require the Transmission Owner to specifically describe how it will conduct work to comply with the Standard in lieu of requiring the Transmission Owner to only identify general objectives.</td></tr>
<tr><td>Hydro-Quebec Transenergie (HQT)</td><td>Disagree</td><td>R1.2 and R1.3 specify calendar year. The individual entities should define the 12 month period for their programs.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comments. The annual work plan may be for a calendar year or for a fiscal year.</td></tr>
<tr><td>Western Area Power Administration, Upper Great Plains Region</td><td>Agree</td><td>The description of the annual plan now appears to require a detailed plan for each line. Under FAC-003-1, Western (UGPR) identified higher priority vegetation during aerial inspection and handled those expediciously. We then addressed a percentage of the lower priority trees based upon a number of agency defined factors (vegetation priority, ground conditions, resource availability, etc). The less rigid annual plan allowed us the freedom to cut the lower priority trees that made the best sense to cut. We are concerned that the additional rigidity will create a ever-changing annual plan because we may have to adjust dozens of lines based on inspections. We question whether it is prudent to occupy finite resources in continually modifying the annual plan when the real benefits accrue from actually performing the vegetation management activities.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comments. The SDT intent is for the Transmission Owner’s Transmission Vegetation Management Program to be developed based on the unique requirements of each Transmission Owner’s system. For example, where the Transmission Owner has a heavily forested or geographically large territory the annual plan may address many transmission lines on a cyclic basis along with additional items found on the vegetation inspections. On the other hand, where the Transmission Owner has a very sparsely forested territory, or a small number of transmission line miles, the Transmission Vegetation Management Program may necessitate an annual plan that only addresses items found on the vegetation inspections. Therefore, the specificity of the annual plan is subject to the discretion of the Transmission Owner. We agree that only the appropriate amount of resources should be applied to the execution and management of the annual plan, provided the overall Transmission Vegetation Management Program is effective.</td></tr>
<tr><td>Progress Energy Florida</td><td>Agree</td><td>Annual Plan should be a defined term in the standard. Without a definition, the term may be interpreted differently by industry and the regulator. The drafting team should raise the prominence of annual plan and define the attributes of an annual plan.</td></tr>
</table>

Organization	Agree?	Question 6 Comment
Response: The SDT thanks you for your comments. The SDT did attempt to address this concern by breaking the annual plan into 4 separate sub-requirements. We feel this may help limit the range of subjective interpretations of this requirement.		
Progress Energy Carolinas	Agree	Annual Plan should be a defined term in the standard. Without a definition, the term may be interpreted differently by industry and the regulator. The drafting team should raise the prominence of annual plan and define the attributes of an annual plan.
Response: The SDT thanks you for your comments. The SDT did attempt to address this concern by breaking the annual plan into 4 separate sub-requirements. We feel this may help limit the range of subjective interpretations of this requirement.		
Southern California Edison Company	Agree	Q6: SCE agrees in part. Proposal R1.3, requiring Transmission Owners to establish an annual maintenance plan is generally acceptable. However, SCE disagrees with including peripheral information in R1.3 and the institution of a separate implementation requirement (R9). Further, we note that some portions of FAC-003-1 (R2) appear to have been transplanted into proposed R1.3 and that the word “shall” has been replaced with the word “should”. SCE believes that inserting the word “shall” into statements that are clearly advisory in nature does not necessarily create enforceable requirements. As proposed, an enforcement auditor might incorrectly determine that the new “requirement” statements in proposed R1.3, describing the need for “flexibility”, “consideration of permitting and scheduling requirements”, and self-determined “methodologies” is a comprehensive list of items for the maintenance plan. Because this list of program elements is not complete, SCE recommends all text following the opening sentence be removed from R1.3 and inserted into the supporting technical paper. SCE respectfully suggests that R1.3 be revised to read: "Specifies a plan that identifies the applicable lines to be maintained and associated work to be performed."
Response: The SDT thanks you for your comments. The consensus of the SDT is the components of an annual work plan must be part of the requirement to ensure that all plans are adequate. Major changes that could affect reliability must be made.		
FirstEnergy	Agree	Although we agree with R1.3, we suggest it be broken up into subrequirements to allow for better clarity to the reader as well as aid in the development of violation severity levels when developed. We suggest the following:R1.3. Require an annual plan that includes the following as a minimum: (Note: Adjustments to the plan within the year are permissible) R1.3.1. It shall identify the applicable lines to be maintained and associated work to be performed during the year. R1.3.2. Is shall be flexible to adjust to changing conditions and to findings from vegetation inspections. R1.3.3. It shall take into consideration permitting and scheduling requirements from landowners or regulatory authorities. R1.3.4. It shall support the objectives of the transmission vegetation management program and use the methodologies outlined in the transmission vegetation management program.

Organization	Agree?	Question 6 Comment
Response: The SDT thanks you for your comments. Requirement R1.3 has been subdivided for clarity in proposed version 2.		
MRO NERC Standards Review Subcommittee	Agree	The MRO suggests removing the words "during the year" from sentence 1 and removing the words "within the year" in sentence 3. The MRO believes that having it only within the plan year is too restrictive.
Response: The SDT thanks you for your comments. By definition an annual plan covers a one year period. This one year period, at the discretion of the Transmission Owner, may or may not be constrained to a calendar year. However, in an effort to make the requirement more concise, the SDT did remove the words "during the year" from the requirement but retained the words "within the year" in the requirement.		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 6 and proposes that the Annual Plan be a defined term.
Response: The SDT thanks you for your comments. The SDT did attempt to address this concern by breaking the annual plan into 4 separate sub-requirements. We feel this may help limit the range of subjective interpretations of this requirement.		
American Electric Power (AEP)	Agree	AEP agrees with these changes.
Response: The SDT thanks you for your comments.		
Platte River Power Authority	Agree	Under the new working in R1., the Transmission Vegetation Management Program no longer has a requirement to include objectives. However, there is a phrase in R1.3. to "support the objectives.. and methodologies outlined in the Transmission Vegetation Management Program". R1.3. should be consistent with the wording in R1.
Response: The SDT thanks you for your comments. The SDT has made changes to address this concern and the word, "objectives" is no longer used in the revised standard.		
American Transmission Company	Agree	ATC agrees with separating the implementation Requirements from the Annual Plan Requirements.
Response: The SDT thanks you for your comments.		
Manitoba Hydro	Agree	Agree with the separation - but suggest that the time horizon of one year be removed as some changes may push the work beyond the current planning year.
Response: The SDT thanks you for your comments. By definition an annual plan covers a one year period. This one year period, at the discretion of		

Organization	Agree?	Question 6 Comment
the Transmission Owner, may or may not be constrained to a calendar year. If findings during the year from Vegetation Inspections justify changes to the plan, such adjustments are allowed as long as they occur within the planning year, not after the fact.		
San Diego Gas & Electric	Agree	To be consistent with R1.3, we recommend that R1.1 be reworded to specify the methodologies and objectives that the Transmission Owner uses to control vegetation.
Response: The SDT thanks you for your comments. The SDT has made changes to address this concern.		
CenterPoint Energy	Agree	See comments to Q4 above as well.
Response: The SDT thanks you for your comments. See response to comments on Q4.		
Great River Energy	Agree	GRE suggests removing the words "during the year" from sentence 1 and removing the words "within the year" in sentence 3. GRE believes that having it only within the plan year is too restrictive.
Response: The SDT thanks you for your comments. By definition an annual plan covers a one year period. This one year period, at the discretion of the Transmission Owner, may or may not be constrained to a calendar year. However, in an effort to make the requirement more concise, the SDT did remove the words "during the year" from the requirement but retained the words "within the year" in the requirement.		
WECC Reliability Coordination	Agree	
Associated Electric Cooperative Inc.	Agree	
SERC Vegetation Management Subcommittee (VMS)	Agree	
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
SERC OC Standards Review	Agree	

Organization	Agree?	Question 6 Comment
Group		
Florida Power & Light	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
Bonneville Power Administration	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	
Exelon	Agree	
Central Maine Power Company	Agree	
Northern California Power Agency (NCPA)	Agree	
Tampa Electric Company	Agree	
Orange and Rockland Utilities Inc.	Agree	
Ameren	Agree	

Organization	Agree?	Question 6 Comment
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Consumers Energy Company	Agree	
National Grid	Agree	
Pacific Gas & Electric Co.	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Duke Energy Corporation	Agree	
Entergy Services	Agree	
Pepco Holdings, Inc	Agree	
Northeast Utilities	Agree	
Buckeye Power, Inc.	Agree	

7. In R1.4 the Standard requires the Transmission Owner to have an Imminent Threat Procedure and specifies elements to be in that procedure. Do you agree with R1.4? If not, please explain.

Summary Consideration: Approximately half of the comments received were critical of the lack of a definition for imminent threat. The SDT prefers to allow the verbiage "an imminent threat of a vegetation-related Sustained Outage" to stand without further definition.

About the same number of commenters objected to the "prescriptive" list of other actions for the Transmission Operator, and that language has been removed from R1.4.

R1.4 Require a process or procedure for response to imminent threats of a vegetation related Sustained Outage. The process or procedure shall specify actions which shall include immediate communication of the threat to the responsible control center.

Deleted: Transmission Operator

Deleted: , and may include actions such as a temporary reduction in line Rating, switching lines out of service, or other actions.

Commenters also expressed a desire to set the procedure for specific internal needs and the SDT modified the language to give that latitude to the Transmission Owner when developing its Imminent Threat procedure.

Some comments referred to parts of the standard not asked about in this question and the SDT directed the commenters to review the changes in R1, R2 and R4.

Organization	Agree?	Question 7 Comment
Associated Electric Cooperative Inc.	Disagree	The language in R1.4, requiring notification of the Transmission Operator, is inconsistent with the Applicability in Section A.4.1.1 which designates the Transmission Owner as the responsible entity.
Response: Thank you for your comment. The main purpose of requirement R1.4 is to enhance the responsible operator's situational awareness of the power system's status. Therefore, the salient requirement of this procedure is notification of the responsible operator of any potential threat to the power system. This requirement does not mandate any action of the responsible operator and thus, this entity would not need to be listed in the Applicability section. Please also note that the wording in R1.4 has been altered to change the "Transmission Operator" to the "responsible control center", to better identify the appropriate responsible party.		
NPCC	Disagree	While we strongly agree that an imminent threat procedure should be required in the Transmission Vegetation Management Program, we disagree with some specific wording in R1.4. R1.4 requires immediate communication of an imminent threat to the Transmission Operator, which we would normally agree with. R2 however requires that the imminent threat procedure be implemented when the Critical Clearance Zone (Critical Clearance Zone) is approached by vegetation. "Approached" is not defined as a specific distance, so this part of the requirement is left up to the individual's interpretation. In cases where the Critical Clearance Zone is

Organization	Agree?	Question 7 Comment
		approached by vegetation no threat to the system is possible if the vegetation is removed before it actually grows into the Critical Clearance Zone . In many cases the vegetation can be removed without taking clearance outages because the Critical Clearance Zone is large, and the conductor and vegetation are still relatively far apart. In such cases there is no need to notify the Transmission Operator, although there is a need to remove the vegetation immediately. We recognize that the opposite is also true, and that in some cases it will be necessary to notify the Transmission Operator because a clearance outage or line de-rating may be required to remove the vegetation. We therefore suggest a simple change to the wording of the second sentence of R1.4. Change "?. specify actions which shall include immediate communication of the threat to the Transmission Operator, and may include actions such as a temporary reduction in line Rating, switching lines out of service, or other actions" to ".. specify actions which may include immediate communication of the threat to the Transmission Operator, a temporary reduction in line Rating, switching lines out of service, or other actions". This change will address the issue which is described above and will allow each Transmission Operator to develop an imminent threat procedure that best fits their system. It should also be noted that many Transmission Operators have imminent threat procedures in place to address all imminent threats to their transmission system, not just threats due to vegetation. It makes sense for Transmission Owners to have only one imminent threat process, therefore the flexibility that can be achieved in the context of this standard would be helpful.
Response: Thank you for your comment. We agree with your comments concerning the Critical Clearance Zone and the elusiveness of the term "approach". Subsequently, the Critical Clearance Zone methodology has been removed from the Standard. The SDT also agrees that the main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of the power system's status. Please also note that the wording has been altered to change the "Transmission Operator" to the "responsible control center" to better identify the appropriate responsible party. The SDT maintains that the salient requirement of this procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system.		
SERC Vegetation Management Subcommittee (VMS)	Disagree	The Requirement as written is too prescriptive and is open to interpretation, from an audit perspective, with use of the term "immediate" communication and a partial list of activities. Many conditions or threats, requiring immediate removal, would not require communication with the Transmission Operator, who is not an applicable entity for this standard. The SERC VMS recommends that R1.4 be deleted. Since this is a "zero tolerance" standard any Transmission Owner will remove any discovered threats to prevent outages. If R1.4 is not deleted, the SERC VMS believes that imminent threats should be a defined term. The definition should be as follows: ?Imminent Threat: A vegetation condition which, if not addressed, will place a transmission line at a significant risk of a Sustained Outage.?
Response: Thank you for your comment. We agree that an imminent threat can exist in many different forms. Part of your concern has been addressed by the removal of the term "immediate". However, the SDT does not agree with removing the imminent threat requirement. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to		

Organization	Agree?	Question 7 Comment
better identify the appropriate party. The salient requirement of the imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system.		
Progress Energy Florida	Disagree	Progress Energy agrees with the need for a Transmission Owner to have an Imminent Threat Procedure and that the Transmission Operator should be immediately notified of imminent threats but only when it is appropriate as defined by the Transmission Owner's imminent threat procedure. We disagree with the requirement to immediately communicate with the Transmission Operator whenever the Critical Clearance Zone is approached. Not every scenario is an issue that requires action by the Transmission Operator: It is possible that the Critical Clearance Zone is being approached by vegetation at the lowest point of the Critical Clearance Zone whereas the conductor may be at its highest point in the Critical Clearance Zone (potentially 30 feet away from the vegetation) -- This typical situation does not merit notification to the Transmission Operator (which is required by FAC-003-2 as currently written).
Response: Thank you for your comment. We agree with your comments concerning the Critical Clearance Zone methodology. Subsequently, the Critical Clearance Zone methodology has been removed from the Standard. The SDT also agrees that the main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please also note that the requirement wording has been altered to change the "Transmission Operator" to the "responsible control center". The SDT feels this better identifies the appropriate party. The SDT maintains that the salient requirement of R1.4 is notifying the responsible operator of any imminent threat to the power system.		
Progress Energy Carolinas	Disagree	Progress Energy agrees with the need for a Transmission Owner to have an Imminent Threat Procedure and that the Transmission Operator should be immediately notified of imminent threats but only when it is appropriate as defined by the Transmission Owner's imminent threat procedure. We disagree with the requirement to immediately communicate with the Transmission Operator whenever the Critical Clearance Zone is approached. Not every scenario is an issue that requires action by the Transmission Operator: It is possible that the Critical Clearance Zone is being approached by vegetation at the lowest point of the Critical Clearance Zone whereas the conductor may be at its highest point in the Critical Clearance Zone (potentially 30 feet away from the vegetation) -- This typical situation does not merit notification to the Transmission Operator (which is required by FAC-003-2 as currently written).
Response: Thank you for your comment. We agree with your comments concerning the Critical Clearance Zone methodology. Subsequently, the Critical Clearance Zone methodology has been removed from the Standard. The SDT also agrees that the main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please also note that the requirement wording has been altered to change the "Transmission Operator" to the "responsible control center". The SDT feels this better identifies the appropriate party. The SDT maintains that the salient requirement of R1.4 is notifying the responsible operator of any imminent threat to the power		

Organization	Agree?	Question 7 Comment
system.		
SERC OC Standards Review Group	Disagree	The Requirement as written is too prescriptive and is open to interpretation from an audit perspective with use of the term “immediate” communication and a partial list of activities. Due to limitations of communication capabilities in the field, "immediate" may not be practical. While the White Paper provides insight into what is acceptable communications to the Transmission Operator, the standard is less prescriptive in describing what is an acceptable communication path to the Transmission Operator. We recommend better descriptions in VSLs, measures and the Reliability Standard Audit Worksheet as to what is acceptable. Many conditions or threats, requiring immediate removal, would not require communication with the Transmission Operator, who is not an applicable entity for this standard. The SERC OCSRG recommends that R1.4 be deleted. Since this is a "zero tolerance" standard any Transmission Owner will remove any discovered threats to prevent outages. If R1.4 is not deleted, the SERC OCSRG believes that imminent threats should be a defined term. The definition should be as follows: “Imminent Threat: A vegetation condition which, if not addressed, will place a transmission line at an immediate risk of a Sustained Outage.”
Response: Thank you for your comment. Part of your concern has been addressed by the removal of the term “immediate”. However, the SDT does not agree with removing the imminent threat requirement. The main purpose of the imminent threat requirement is to enhance the responsible control center’s situational awareness of reliability dangers to the power system. Please note that this requirement’s wording has also been altered to change the designation “Transmission Operator” to the “responsible control center” to better identify the appropriate party. The salient requirement of the imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system and field communication capabilities. The SDT also feels that it is important for the aspects of the imminent threat procedure and the triggers be defined by the Transmission Owner. The Violation Severity Levels for this requirement are now binary and self explanatory. The SDT is prepared to provide input in the revision of RSAWs, but under current practice, RSAWs are not developed by standard drafting teams.		
Florida Power & Light	Disagree	The definition of Imminent Threat procedure should be included in the Standard. As FERC has stated with regard to the definition of sabotage, the industry should come up with a standard definition and it should not vary from company-to-company. FPL further disagrees with defining Imminent Threat only in a white paper as proposed by some. The Standard should not refer to other reference documents, especially when it is to add clarity and should define the Imminent Threat procedure as well as its requirements within the body of the Standard.
Response: Thank you for your comment. The SDT disagrees with your comments. We feel that the Transmission Owner should have the flexibility to not only develop the imminent threat procedure but also define the triggers needed for its particular system. The main purpose of the imminent threat requirement is to enhance the responsible control center’s situational awareness of reliability dangers to the power system. The notification requirement is a mandatory requirement for all Transmission Owners. Please note that this requirement’s wording has also been altered to change the designation “Transmission Operator” to the “responsible control center” to better identify the appropriate party. Beyond this, it is left to the		

Organization	Agree?	Question 7 Comment
Transmission Owner to develop all other imminent threat procedure components.		
Southern Company	Disagree	The standard requirement, as written, requires the "immediate notification" of the operator. This standard requirement could be interpreted to mandate that this notification take place prior to any other action. There could be times that this communication would take up valuable time needed to relieve the immediate threat. The requirement should be modified to list examples of appropriate actions that could be taken. The Transmisison Owner should be allowed the flexibility of developing a communication process that ensures timely notification of a threat and the proper channels of communication that will be utilized in making the notification. The present wording in the standard alone suggests the individual observing the threat in the field is directly responsible for communicating with the Transmission Operator while the whitepaper tends to be more flexible. The Transmission Owner may wish to have the vegetation contractor notify the Transmisison Owner's forester who in turn will notify the Transmission Operator. While the whitepaper does an adequate job describing acceptable responses, the standard does not. It is recommend the standard, VSL, and Reliability Standard Audit Worksheet better explain what is an acceptable response to the Transmission OwnerP. The requirement then goes on to address specific actions the operator "may" take in response to the notification. The imminent threat processes should be limited to the steps taken to notify the Transmission Operator in a timely manner. FAC-003 is not the appropriate place to address Transmission Operator decisions resulting from notification of a threat to the system.
Response: Thank you for your comment. Part of your concern has been addressed by the removal of the term “immediate”. We agree that the main purpose of this requirement is to enhance the responsible control center’s situational awareness of reliability dangers to the power system. Further, please note that the requirement wording has also been altered to change the designation “Transmission Operator” to the “responsible control center” to better identify the appropriate party. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system and field communication capabilities. The Violation Severity Levels for this requirement are now binary and self explanatory. The SDT is prepared to provide input in the revision of RSAWs, but under current practice, RSAWs are not developed by standard drafting teams.		
E.ON U.S.	Disagree	The Requirement as written is too prescriptive and is open to interpretation, from an audit perspective, with use of the term “immediate” communication and a partial list of activities. Many conditions or threats, requiring immediate removal, would not require communication with the Transmission Operator, who is not an applicable entity for this standard. We suggest that R1.4 be deleted. Since this is a "zero tolerance" standard any Transmission Owner will remove any discovered threats to prevent outages. If R1.4 is not deleted, we believe that imminent threats should be a defined term. The definition should be as follows: “Imminent Threat: A vegetation condition which, if not addressed, will place a transmission line at a significant risk of a Sustained Outage.”
Response: Thank you for your comment. We agree that an imminent threat can exist in many different forms. Part of your concern has been addressed by the removal of the term “immediate”. However, the SDT does not agree with removing the imminent threat requirement. The main		

Organization	Agree?	Question 7 Comment
purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of this procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system.		
Midwest ISO Stakeholders Standards Collaborators	Disagree	Transmission Owners should have a Vegetation Imminent Threat Procedure, and "Vegetation Imminent Threat" should be a defined term, defined as: "Vegetation observed in the field encroaching upon a conductor within a distance that is twice the Gallet clearance distances referenced in Table I of the draft standard FAC-003-2." In this case, the threat would require an immediate response and would include communication to the Transmission Operator. From there, the actions that the operator decides to take will be dependent on the incident and system conditions. We do not need to be prescriptive with this requirement but rather allow the Transmission Operator and appropriate field personnel the flexibility to make the right decisions to safely, promptly and appropriately remove the vegetation threat. From a Transmission Owner's perspective, many situations can constitute an imminent threat but this approach will clearly define a "Vegetation Imminent Threat" as it relates to the Purpose of this standard. See our related comment on #11 below.
Response: Thank you for your comment. We agree that many situations can constitute an imminent threat. While we do not agree that an imminent threat should be defined in the Standard, we do agree that the Transmission Owner should have the flexibility to develop an imminent threat procedure that allows the appropriate decisions to address the vegetation threat. This requirement allows the Transmission Owner to develop an imminent threat procedure that best fits its system. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The SDT feels this is a better approach than to have a rigid definition of an imminent threat procedure.		
SERC Compliance Staff	Disagree	SERC staff agrees with the concept of an imminent threat procedure, but disagrees with this requirement in its current form. The use of the word "immediate" is ambiguous. There are many conditions or threats that may require immediate removal, but would not require communication with the Transmission Operator and may require communication with another entity. SERC staff suggests that the proper communication paths be outlined by the Transmission Owner. Imminent threats should be a defined term, however SERC staff has not developed an objective, unambiguous definition.
Response: Thank you for your comment. Part of your concern has been addressed by the removal of the term "immediate". We agree that the main purpose of the imminent threat requirement is the timely communication of a threat to the responsible operator. Therefore, the requirement wording has been altered to change the designation "Transmission Operator" to the "responsible control center". The main purpose of this requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. While we do agree that the Transmission Owner should outline the proper communication paths, we do not agree that an imminent threat should be defined in the Standard. The SDT feels the		

Organization	Agree?	Question 7 Comment
Transmission Owner should have the flexibility to develop an imminent threat procedure that best fits its system.		
ITC HOLDINGS	Disagree	Agree & Disagree with the question: Agree with the need to have an Imminent Threat Procedure and upon discovery of an IT, the Transmission Operations (Transmission Owner) should be notified. We Disagree however, with the requirement as written as its too prescriptive and is open to interpretation, from an audit perspective, with use of the term “immediate” communication and a partial list of activities that the Transmission Owner may consider. Decisions on what specific system operating actions that could be taken are beyond the responsibility of the vegetation management personnel. Disagree with the need to implement the imminent threat procedure merely because a Critical Clearance Zone is being approached. It is possible that the Critical Clearance Zone is being approached by vegetation at the lowest point of the Critical Clearance Zone where the conductor may be at its highest point in the Critical Clearance Zone , (potentially 20 or 30 feet from vegetation) and wouldn’t necessitate notification to the Transmission Owner. Is there a desired distance from the Critical Clearance Zone where this procedure must be implemented since all vegetation within a Right-of-Way will approach the Critical Clearance Zone as it grows? R1.4 should be changed to ?Require a process for response to vegetation related imminent threat to applicable lines and not the Critical Clearance Zone
Response: Thank you for your comment. We agree with your comments concerning the Critical Clearance Zone and the elusiveness of the terms “approach” and “immediate”. Subsequently, the Critical Clearance Zone methodology has been removed from the Standard. Also, the term “immediate” has been removed. The main purpose of the imminent threat requirement is to enhance the responsible control center’s situational awareness of the power system’s status. Please also note that the wording has been altered to change the “Transmission Operator” to the “responsible control center” to better identify the appropriate responsible party. The SDT maintains that the salient requirement of the imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system.		
Tennessee Valley Authority	Disagree	TVA recommends that R1.4 and R2 both be removed from this Standard. This is a "zero tolerance" Standard with significant penalties for outage violations. These penalty conditions are the necessary and sufficient conditions for the Transmission Owner to immediately react to any discovered threats to prevent potential outages.
Response: Thank you for your comments. While the drafting team does agree that the penalties for the “zero tolerance” aspect of the Standard certainly provide a strong incentive, we still feel that a requirement for an imminent threat procedure should be included in the Standard. The main purpose of the imminent threat requirement is to enhance the responsible control center’s situational awareness of reliability dangers to the power system. Please note that this requirement’s wording has been altered to change the designation “Transmission Operator” to the “responsible control center” to better identify the appropriate party. The salient part of this procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, the Transmission Owner should develop all other components of the imminent threat procedure to best fit its system.		

Organization	Agree?	Question 7 Comment
American Electric Power (AEP)	Disagree	AEP agrees with the need for a Transmission Owner to have an Imminent Threat Procedure and that the Transmission Operator should be immediately notified of imminent threats. However, AEP disagrees with the requirement that the Transmission Operator be notified merely because the Cricitical Clearance Zone (Critical Clearance Zone) has been approached. It is possible that the Critical Clearance Zone is encroached by vegetation at the lowest point of the Critical Clearance Zone whereas the conductor may be at its highest point in the Critical Clearance Zone (potentially 20 or 30 feet away from the vegetation). This situation does not merit notification to the Transmission Operator. Please also refer to our comments regarding Critical Clearance Zone in AEP's responses to Questions 15 and 18.
Response: Thank you for your comment. We agree with your comments concerning the Critical Clearance Zone and the elusiveness of the term “approach”. Subsequently, the Critical Clearance Zone methodology has been removed from the Standard. The SDT feels that the main purpose of the imminent threat requirement is to enhance the responsible control center’s situational awareness of the power system’s status. Please also note that the wording has been altered to change the “Transmission Operator” to the “responsible control center” to better identify the appropriate responsible party. The SDT maintains that the salient requirement of this procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system.		
Tampa Electric Company	Disagree	TECO aggres with the need for the Imminent Threat Procedure. However, the use of the new Critical Clearance Zone could create a "fill in the blank" standard. We need to lock these clearances down as an industry so as to define what is an imminent threat and what the Critical Clearance Zone is in terms of specific distances.
Response: Thank you for your comments. The SDT agrees with your concern of having a standard with “fill in the blank” requirements. We have made some major changes to this requirement due to the overwhelming response from industry that the imminent threat requirement was needed but should not be overly prescriptive. The main purpose of the imminent threat requirement is to enhance the responsible control center’s situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation “Transmission Operator” to the “responsible control center” to better identify the appropriate party. The salient part of the imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. **Using the Critical Clearance Zone as an undefined “trigger” for implementing the imminent threat process has been removed from the Standard. The Critical Clearance Zone methodology has been deleted from the Standard.**		
Orange and Rockland Utilities Inc.	Disagree	While we agree that the imminent threat procedure should be included in the Transmission Vegetation Management Program, the requirement is overly prescriptive and should be revised to allow Transmission Owners flexibility to develop imminent threat procedures which best fit their systems and protocols. We recommend that R1.4 be reworded as follows: "Require a process or procedure for response to vegetation-related imminent threats to applicable lines. The imminent threat procedure shall require action to eliminate vegetation-related imminent threats, and shall be implemented upon discovery of such conditions". In addition, the definition of "Imminent Threat" should be defined. We suggest the following: "A condition which places a

<table>
<tr><th>Organization</th><th>Agree?</th><th>Question 7 Comment</th></tr>
<tr><td></td><td></td><td>transmission line at significant risk of an outage in the very near term". An example of a vegetation-related imminent threat would be an uprooted tree leaning precariously toward a conductor which is certain to make contact with the conductor as the tree falls. Many Transmission Operators have imminent threat procedures in place to address all imminent threats to their transmission systems, not just imminent threats due to vegetation. In many cases it would make sense for Transmission Owners to have one imminent threat process that covers all imminent threat conditions. The flexibility being recommended would facilitate this.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. The SDT agrees that the requirement was overly prescriptive. The requirement has been revised to focus on the main purpose of the imminent threat requirement; which is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient part of this procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its systems and protocols; thereby providing for the flexibility that you have suggested. Along with this line of reasoning, we do not agree that an imminent threat should be defined in the Standard. Again, the SDT feels that the Transmission Owner should have the flexibility to define what constitutes an imminent threat to its individual power system. This flexibility also allows the Transmission Owner to have one imminent threat process in place to cover all imminent threats to its transmission systems, not just imminent threats due to vegetation as you have noted.</td></tr>
<tr><td>American Transmission Company</td><td>Disagree</td><td>We agree that entities should have a Vegetation Imminent Threat Procedure, but that the term should be defined. Also see related comments to Question #11.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. We have made some major changes to this requirement due to the overwhelming response from industry that the imminent threat requirement was needed, as long as it was not an overly prescriptive requirement. We do not agree that an imminent threat should be defined in the Standard. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its system. The SDT feels this is a better approach than to have a rigid definition of an imminent threat procedure.</td></tr>
<tr><td>Nebraska Public Power District</td><td>Disagree</td><td>NPPD agrees that a Transmission Owner should have an imminent threat procedure and the Transmission Owner be immediately notified of any threats. NPPD disagrees with prescribing what needs to be done as a result of the threat. This is condition based and staff can make the right decision as to what corrective actions are necessary.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. The SDT agrees that prescribing what needs to be done as a result of the threat should not be included as part of the Standard requirement. This language has been removed from the text as you have suggested. The SDT also agrees that the main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system.</td></tr>
</table>

Organization	Agree?	Question 7 Comment
Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its system.		
Consumers Energy Company	Disagree	Consumers Energy believes that each Transmission Owner/Operator should have a Vegetation Imminent Threat Procedure. We disagree with this requirement because "vegetation imminent threat" is not defined in the standard. As interpreted, the "vegetation imminent threat" is only what is needed to avoid violating the Gallet formula minimum distance which would allow vegetation approaching close to 3 feet of separation on 345 kV conductors. At this distance, removal of the tree cannot occur without removing the line from service per OSHA rules. Therefore, the tree can "cause" an outage but be acceptable under this standard. Consumers Energy believes that vegetation must be maintained so that extraordinary measures needed to remove the vegetation threat do not have to occur in order to complete the work. Thus, the minimum distance to "trigger" an imminent threat must be greater than the OSHA minimum working distance and therefore the Gallet formula does not provide the protection that FERC demands. During high load periods options a system operator may have to mitigate the vegetation threat may not be available; you may not be able to remove the line from service, derate the line, etc., so the operator must "hope" to get through the high load period without the vegetation causing a outage. Allowing vegetation to approach the Gallet formula distance is unacceptable and severely decreases the reliability of the system.
Response: Thank you for your comment. The SDT does not agree that a vegetation imminent threat should be defined in the Standard. The Critical Clearance Zone methodology has been removed from the Standard. We feel that the Transmission Owner should have the flexibility to not only develop the imminent threat procedure but also define the triggers needed for its particular system. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. The notification requirement is a mandatory requirement for all Transmission Owners. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The SDT maintains that the salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its system. Aside from the negative economic and operational impacts associated with unscheduled facility outages, failures by the Transmission Owner to effectively execute follow up activities and procedures will most likely lead to a violation(s) of other requirements related to Minimum Vegetation Clearance Distance (MVCD) encroachment or sustained outages.		
Ameren	Disagree	Transmission Owners should have a Vegetation Imminent Threat Procedure, and "Vegetation Imminent Threat" should be a defined term, defined as: "Vegetation observed in the field encroaching upon a conductor within a distance defined in the Vegetation Management plan." In this case, the threat would require an immediate response and would include communication to the Transmission Operator. From there, the actions that the operator decides to take will be dependent on the incident and system conditions. We do not need to be

<table>
<tr><th>Organization</th><th>Agree?</th><th>Question 7 Comment</th></tr>
<tr><td></td><td></td><td>prescriptive with this requirement but rather allow the Transmission Operator and appropriate field personnel the flexibility to make the right decisions to safely, promptly and appropriately remove the vegetation threat. From a Transmission Owner's perspective, many situations can constitute an imminent threat but this approach will clearly define a "Vegetation Imminent Threat" as it relates to the Purpose of this standard. While a definition of "Vegetation Imminent Threat - Vegetation observed in the field encroaching upon a conductor within a distance that is twice the Gallet clearance distances referenced in Table I of the draft standard FAC-003-2" would be acceptable and far superior to that which is proposed, it will still be difficult for field personnel to identify, at each foot of a transmission circuit, wherein twice the Gallet distance would be found. See comment on #11 below.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. We agree with your assessment that the Standard needs an imminent threat requirement, but as it was written, the requirement was overly prescriptive. As a result, and because much of the industry agreed with you, we have made some major changes to this requirement. The main purpose of the imminent threat requirement is to enhance the responsible control center’s situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation “Transmission Operator” to the “responsible control center” to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system.

We further agree that many situations can constitute an imminent threat, distance from the vegetation to the conductor being only one of such situations, so the references to the Critical Clearance Zone methodology as a defined “trigger” for implementing the imminent threat process has been removed from the Standard. For that matter, the Critical Clearance Zone methodology has been deleted from the Standard. While we do not agree that an imminent threat should be defined in the Standard, we do agree that the Transmission Owner should have the flexibility to develop an imminent threat procedure that allows the appropriate decisions to address the vegetation threat. The requirement, as it has been reworded, allows the Transmission Owner to develop an imminent threat procedure that best fits its system. The SDT feels this is a better approach than to have a rigid definition of an imminent threat procedure.</td></tr>
<tr><td>Consolidated Edison Company of New York (CECONY)</td><td>Disagree</td><td>CECONY currently has procedures that mandate response to imminent threats. The Standard should be made more general and not identify the specific actions that shall be taken in the procedure. The second sentence of R1.4 should be deleted and the first sentence should read, 'Require a process or procedure to respond to vegetation-related imminent threats." This adds the necessary flexibility that utilities require and avoids additional redundant processes or procedures from being developed.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. The SDT agrees that the requirement should be more general and has revised the requirement to focus on the main purpose of the imminent threat requirement; which is, to enhance the responsible control center’s situational awareness of reliability dangers to the power system. Please note that this requirement’s wording has also been altered to change the designation “Transmission Operator” to the “responsible control center” to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its systems and protocols, thereby providing for the flexibility that you have suggested.</td></tr>
</table>

Organization	Agree?	Question 7 Comment
Duke Energy Corporation	Disagree	Duke believes that Transmission Owners should have a Vegetation Imminent Threat Procedure, and "Vegetation Imminent Threat" should be a defined term, defined as: "Vegetation observed in the field encroaching upon a conductor within a distance that is twice the Gallet clearance distances referenced in Table I of the draft standard FAC-003-2." In this case, the threat would require an immediate response and would include communication to the Transmission Operator. From there, the actions that the operator decides to take will be dependent on the incident and system conditions. We do not need to be prescriptive with this requirement but rather allow the Transmission Operator and appropriate field personnel the flexibility to make the right decisions to safely, promptly and appropriately remove the vegetation threat. From a Transmission Owner's perspective, many situations can constitute an imminent threat but this approach will clearly define a "Vegetation Imminent Threat" as it relates to the Purpose of this standard. See our related comment on #11 below.
Response: Thank you for your comment. While we do not agree that an imminent threat should be defined in the Standard, we do agree with your assessment that the Standard needs an imminent threat requirement, but as it was written, the requirement was overly prescriptive. As a result, and because much of the industry agreed with you, we have made some major changes to this requirement. The Critical Clearance Zone methodology has been deleted from the Standard. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any potential threat to the power system. Beyond this, it is left to the Transmission Owner to determine the "triggers", follow up activities, and procedures that best fit its system; thereby providing for the flexibility that you have suggested. The SDT feels this is a better approach than to have a rigid definition of an imminent threat procedure.		
Entergy Services	Disagree	1. The requirement should state that each Transmission Owner will be responsible for creating and maintaining a Vegetation Imminent Threat Process. This process will clearly define how the Transmission Owner defines a vegetation imminent threat. 2. The requirement needs to state that only vegetation conditions identified, to the Transmission Owner, by regular field inspections, including aerial inspections, and other internal and external verifiable reports of vegetation imminent threats will be managed through this process. 3. If the standard requires a process to mitigate potential immediate threats to the system, the term ?vegetation imminent threat? must be defined. This definition must not delineate the precise steps that are required to be taken to allow experts as many options as necessary to address each vegetation condition specifically. 4. The list of possible mitigating actions should be removed from the standard since it is not an all inclusive list. Listing these actions in the standard may imply that the entity must do one or all of the actions to be in compliance. The entity must have sufficient latitude to evaluate each possible vegetation condition and apply the most appropriate mitigation steps, up to and including the removal of the identified vegetation.

Organization	Agree?	Question 7 Comment
Response: Thank you for your comments. **1. The SDT prefers to allow the verbiage "an imminent threat of a vegetation-related Sustained Outage" to stand without further definition. The SDT agrees that the Standard needs an imminent threat requirement. However, as it was written for the initial posting, the requirement was overly prescriptive. As a result, and because much of the industry agreed with you, the SDT has made some changes to this requirement. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to permit communication with the relevant entity for the Transmission Owner. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the "triggers", follow up activities, and procedures that best fit its system, thereby providing for the flexibility that you have suggested. The SDT feels this is a better approach than to have a rigid definition of an imminent threat procedure.** **2. See response 1 above.** **3. See response 1 above.** **4. See response 1 above.**		
Salt River Project	Disagree	Agree with R1.4, however with the suggested change: Remove the language "?and may include actions such as a temporary reduction in line Rating, switching lines out of service, or other actions.". Any standard should not contain advisory-type language, it should be declarative in tone. The suggested actions are not the responsibility of the vegetation management program.
Response: Thank you for your comment. The advisory type language has been removed from the requirement as you have suggested. The SDT also agrees that these "advisory" actions could fall outside the responsibility of some utilities' Transmission Vegetation Management Program. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation.		
Northeast Utilities	Disagree	Agree with the need to have and implement when necessary an imminent threat procedure. Disagree with the need to implement the imminent threat procedure merely because a Critical Clearance Zone is being approached, as required by R2. Is there a desired distance from the Critical Clearance Zone where this procedure must be implemented, since all vegetation within a right-of-way will "approach" the Critical Clearance Zone as it grows? How will time of year and operating conditions be factored in, which may change the requirements to perform control during periods of low temperature or low load? It would not be necessary to perform all the requirements of an imminent threat procedure when there is adequate clearance to schedule the

Organization	Agree?	Question 7 Comment
		work without jeopardizing the reliability of the system. For example, in mid winter a line is 8 feet from a tree - there is little chance of the line reacing maximum sag at that time of year and the present condition does not constitute an imminent threat at that time. Also, disagree with the requirement for the imminent threat procedure to include actions that could be taken by the Transmission OwnerP (reduction in line rating, switching). The requirement should be limited to notifications to the Transmission OwnerP, since decisions on what specific system operating actions to take are beyond the responsibility of the Transmission Owner. The decision on what actions to take needs to be performed either by the Transmission OwnerP, or by the Transmission OwnerP in conjunction with the Transmission Owner.
Response: Thank you for your comments. We agree with your comments concerning the Critical Clearance Zone and the elusiveness of the term "approach". Subsequently, the Critical Clearance Zone methodology as it refers to the imminent threat process has been removed from the Standard. The SDT also agrees that the main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of the power system's status. . Please also note that the wording has been altered to change the "Transmission Operator" to the "responsible control center" to better identify the appropriate responsible party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system, and allows the Transmission Owner to make appropriate decisions on follow up actions.		
Hydro-Quebec Transenergie (HQT)	Disagree	While we strongly agree that an imminent threat procedure should be required in the Transmission Vegetation Management Program, we disagree with some specific wording in R1.4. R1.4 requires immediate communication of an imminent threat to the Transmission Operator, which we would normally agree with. R2 however requires that the imminent threat procedure be implemented when the Critical Clearance Zone (Critical Clearance Zone) is approached by vegetation. "Approached" is not defined as a specific distance, so this part of the requirement is left up to the individual's interpretation. In cases where the Critical Clearance Zone is approached by vegetation no threat to the system is possible if the vegetation is removed before it actually grows into the Critical Clearance Zone . In many cases the vegetation can be removed without taking clearance outages because the Critical Clearance Zone is large, and the conductor and vegetation are still relatively far apart. In such cases there is no need to notify the Transmission Operator, although there is a need to remove the vegetation immediately. We recognize that the opposite is also true, and that in some cases it will be necessary to notify the Transmission Operator because a clearance outage or line de-rating may be required to remove the vegetation. We therefore suggest a simple change to the wording of the second sentence of R1.4. Change "?. specify actions which shall include immediate communication of the threat to the Transmission Operator, and may include actions such as a temporary reduction in line Rating, switching lines out of service, or other actions" to ".. specify actions which may include immediate communication of the threat to the Transmission Operator, a temporary reduction in line Rating, switching lines out of service, or other actions". This change will address the issue which is described above and will allow each Transmission Operator to develop an imminent threat procedure that best fits their system. It should also be noted that many Transmission Operators have imminent threat procedures in place to address all imminent threats to their transmission system,

Organization	Agree?	Question 7 Comment
		not just threats due to vegetation. It makes sense for Transmission Owners to have only one imminent threat process; therefore the flexibility that can be achieved in the context of this standard would be helpful.
Response: Thank you for your comments. We agree with your comments concerning the Critical Clearance Zone and the elusiveness of the term “approach”. Subsequently, the Critical Clearance Zone methodology has been removed from the Standard. The SDT feels that the main purpose of the imminent threat requirement is to enhance the responsible control center’s situational awareness of the power system’s status. The wording about other follow up actions that could be taken has been removed from the requirement. Please also note that the wording has been altered to change the “Transmission Operator” to the “responsible control center” to better identify the appropriate responsible party. The SDT maintains that the salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system.		
Pepco Holdings, Inc	Disagree	While an imminent threat procedure is prudent and reasonable, it does not need to consider a Critical Clearance Zone as addressed in our comments on other questions. In fact, one can quickly provide examples of imminent threats when the threat is not even on the right of way. The Transmission Owner should simply have an imminent threat procedure to address identified imminent or potential imminent threats.
Response: Thank you for your comment. We agree with your comments concerning the Critical Clearance Zone methodology. Subsequently, the Critical Clearance Zone methodology has been removed from the Standard. The SDT feels that the main purpose of the imminent threat requirement is to enhance the responsible control center’s situational awareness of the power system’s status. Please also note that the requirement wording has been altered to change the “Transmission Operator” to the “responsible control center” to better identify the appropriate responsible party. The SDT maintains that the salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, the SDT agrees that it should be left to the Transmission Owner to develop an imminent threat procedure that best fits its system.		
Southern California Edison Company	Agree	Q7: SCE agrees in part with the content of R1.4 because of its similarity to existing requirement R1.5 in FAC-003-1. However, we disagree with the drafter’s inclusion of peripheral information following the first sentence. We also note that the second sentence of proposed R1.4 includes both a requirement and a recommendation. SCE believes this and similar recommendations are best suited for the supporting technical paper. SCE respectfully suggests that R1.4 be revised to read: "Specify a process or procedure for communicating an impending vegetation-to-line contact that may result in a sustained outage and the appropriate response measures.”
Response: Thank you for your comment. The SDT feels that the main purpose of the imminent threat requirement is to enhance the responsible control center’s situational awareness of the power system’s status. We agree with your suggestions to exclude some of the peripheral language included in this requirement. Thus, the SDT has removed references to the Critical Clearance Zone, the word “immediate”, and the wording referring to other actions that may be taken by the responsible operator. Please also note that the wording has been altered to change the “Transmission		

Organization	Agree?	Question 7 Comment
Operator" to the "responsible control center" to better identify the appropriate responsible party.		
Western Utility Arborists	Agree	We agree with 1.4, with the following qualification: Any standard that is developed should not contain advisory-type language" it should be declarative in tone. For example, in R1.4, the ending clause that begins "and may include actions" should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program.
Response: Thank you for your comments. The advisory type language has been removed from the requirement as you have suggested. The SDT also agrees that these "advisory" actions could fall outside the responsibility of some utilities' Transmission Vegetation Management Program. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation.		
Bonneville Power Administration	Agree	BPA agrees with 1.4, with the following change. The ending phrase: "and may include actions such as a temporary reduction in line Rating, switching lines out of service, or other actions" should be eliminated. Not only does BPA feel it is inappropriate to use advisory-type rather than declarative language in a Standard, BPA feels it is also questionable to give examples of imminent response actions that are often not within the direct capability of a vegetation program to enact. Eliminating the reference to these possible actions leaves it up to the Transmission Operator to decide what the eminent threat response is.
Response: Thank you for your comment. The advisory type language has been removed from the requirement as you have suggested. The SDT also agrees that these "advisory" actions could fall outside the direct capability of some utilities' Transmission Vegetation Management Program. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation.		
FirstEnergy	Agree	The safety of the personnel required to remove a tree or vegetation on or near an energized conductor must be considered when implementing the imminent threat procedure. Although this is a reliability standard, the safety of the personnel may be one "trigger" to implement the imminent threat procedure. That being said, the workers on site, in their judgment, are not able to remove the vegetation safely then the imminent threat procedure would be implemented. See comments for Critical Clearance Zone .
Response: Thank you for your comment. The SDT also believes human safety must be major consideration in this requirement. The Transmission		

Organization	Agree?	Question 7 Comment
Owner may include in its Imminent Threat procedure appropriate considerations for personnel safety as a trigger. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. The SDT made major changes to make the requirement less prescriptive. Also, the wording has been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation. The Critical Clearance Zone methodology has been removed from the Standard.		
MRO NERC Standards Review Subcommittee	Agree	The MRO agrees and believes that it is very important for the applicable entities to posses a Imminent Threat Procedure. The MRO also believes that the term "Imminent Threat" is subjective an should be defined.
Response: Thank you for your comment. We have made some major changes to this requirement due to the overwhelming response from industry that the imminent threat requirement was needed, as long as it was not an overly prescriptive requirement. We do not agree that an imminent threat should be defined in the Standard. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its system. The SDT feels this is a better approach than to have a rigid definition of an imminent threat procedure.		
Western Area Power Administration, Rocky Mountain Region	Agree	The Technical Reference document could be expanded to explain that a well rounded Imminent Threat Procedure should contain many mitigation alternatives to appropriately address a wide range of field situations, including a "no immediate field action is required" option. For example, further investigation of a potential imminent threat situation may reveal that the situation has been erroneously reported or incorrectly measured and therefore no immediate vegetation removal actions are required. A utility's Imminent Threat Procedure may also address situations beyond just vegetation related incidents.
Response: Thank you for your comment. The SDT agrees that many situations can constitute an imminent threat beyond just vegetation related incidents. The requirement has been rewritten to focus on the main purpose of the imminent threat requirement; which is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any potential threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit the wide range of field situations that are possible to encounter.		
Platte River Power Authority	Agree	Imminent threat is not a defined term in the NERC Glossary of Terms so it could be construed as a fill-in-the-blank requirement by FERC as each Transmission Owner could define Imminent Threat differently. Imminent threat should be defined or the requirement should be reworded to define what types of situations would require a procedure. Also, the language, "and may include actions such as a temporary reduction in line rating, switching

Organization	Agree?	Question 7 Comment
		lines out of service, or other actions" should be removed from the standard but could be included in the imminent threat procedure or definition.
Response: The SDT has made some major changes to this requirement due to the overwhelming response from industry that the imminent threat requirement was needed, as long as it was not an overly prescriptive requirement. For instance, we agree that the wording referring to other follow up actions that may be taken by the operator is too prescriptive and has been removed from this requirement. **The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The SDT feels this is a better approach than to have a rigid definition of an imminent threat procedure. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit the wide range of field situations that are possible to encounter.**		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	The USFS would be expecting the Transmission Owner to be documenting the imminent threat procedures in an operating plan or corridor management plan that would be approved by the designated USFS decision maker. If such procedures are documented in the Transmission Owner's Transmission Vegetation Management Program and are compatible with USFS resource management direction, then the imminent threat procedures could be incorporated in the agency-approved operating plan by reference. If the Transmission Owner disputes any restrictions that are placed by the USFS on the imminent threat procedures, the USFS has an administrative appeals process which the Transmission Owner can use, but those procedures can be time-consuming and probably would not be perceived by the Transmission Owner as being neutral for negotiation purposes. It might help if a third federal party like NERC could help resolve disputes between the Transmission Owner and the USFS on the imminent threat procedures. Although the USFS would object to unreasonable intrusion of NERC into normal USFS land management prerogatives, imminent threat procedures would seem to be a topic for which NERC should take a very strong position, especially with a standard that identifies minimum vegetation clearances as related to prevention of arcing potential, or in other words, vegetation that should be considered hazardous and in immediate need of treatment.
Response: Thank you for your comments. The SDT developed this standard to apply to Transmission Owners in support of bulk electric system reliability. While there may be similar areas of regulation between the purview of NERC and the USFS, this standard is not intended to be incompatible with any USFS resource management direction. That being said, any NERC standard approved by the FERC does not need to be incorporated into "the agency-approved operating plan". In regard to the suggestion that NERC assist in resolving disputes between USFS and Transmission Owners, this would be beyond the scope of NERC. **The SDT suggests that USFS and affected Transmission Owners review language in permits and change that language to allow perpetual ingress and egress and vegetation maintenance without case-by-case application and review. Such a change would prevent current problems where it takes**		

Organization	Agree?	Question 7 Comment
upwards of one year before vegetation maintenance is allowed to proceed. **The SDT has made some major changes to this requirement due to the overwhelming response from industry that the imminent threat requirement was needed, as long as it was not an overly prescriptive requirement. For instance, we agree that the wording referring to other follow up actions that may be taken by the operator is too prescriptive and has been removed from this requirement.** **The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The SDT feels this is a better approach than to have a rigid definition of an imminent threat procedure. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit the wide range of field situations that are possible to encounter.**		
Manitoba Hydro	Agree	Suggest removing, "and may include actions such as a temporary reduction in line rating, switching lines out of service, or other actions", as this is outside the scope of a vegetation management program.
Response: Thank you for your comment. The language you mention has been removed from the requirement as you have suggested. The SDT agrees that these actions could fall outside the scope of some utilities' Transmission Vegetation Management Program. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation.		
Pacific Gas & Electric Co.	Agree	PG&E agrees an imminent threat procedure is a critical component of the standard and should be contained in the Transmission Vegetation Management Program. See additional comments for Q11.
Response: Thank you for your comment. See the responses to comments on Q11.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	We agree with 1.4, with the following qualification: Any standard that is developed should not contain advisory-type language? it should be declarative in tone. For example, in R1.4, the ending clause that begins "and may include actions" should be removed because it is advisory in nature. The suggested actions are not even applicable under the scope of a vegetation management program.
Response: Thank you for your comment. The advisory type language has been removed from the requirement as you have suggested. The SDT also agrees that these "advisory" actions could fall outside the scope of some utilities' Transmission Vegetation Management Program. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system.		

Organization	Agree?	Question 7 Comment
Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any potential threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation		
San Diego Gas & Electric	Agree	We recommend that any advisory language be removed, and replaced with a declaration to the utilities.
Response: Thank you for your comment. The advisory type language has been removed from the requirement as you have suggested, The remaining declaratory language addresses the main purpose of the imminent threat requirement which is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any potential threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation		
WECC	Agree	But for clarity, "Imminent Threat Procedure" should be replaced with "Vegetation Imminent Threat Procedure".
Response: Thank you for your comment. The SDT believes that the context is sufficiently clear.		
Arizona Public Service Company	Agree	APS agrees with 1.4, with the following qualification: Any standard that is developed should not contain advisory-type language? it should be declarative in tone. For example, in R1.4, the ending clause that begins "and may include actions" should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program.
Response: Thank you for your comment. The advisory type language has been removed from the requirement as you have suggested. The SDT also agrees that these "advisory" actions could fall outside the responsibility of some utilities' Transmission Vegetation Management Program. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation.		
Baltimore Gas & Electric Company	Agree	This requirement references Danger trees which according to ANSI A-300, Part 7 is any tree that could fall on the conductor. Should this more appropriately be changed to Hazard tree which is a structurally unsound tree? It might be helpful if an imminent threat were defined, e.g. trees that are presently encroaching in or near the Critical Clearance Zone , or trees that by virtue of their hazardous condition appear to be likely to fall into or near the Critical Clearance Zone in the near future. (or just leave the explanation to the White Paper)

Organization	Agree?	Question 7 Comment
Response: Thank you for your comment. We agree with most of your comments and have made some major changes to this requirement due to the overwhelming response from industry that the imminent threat requirement was needed, as long as it was not an overly prescriptive requirement. Many situations can constitute an imminent threat, "danger" or "hazard" trees being only one of those situations. Further, due to the undefined "triggers" associated with the Critical Clearance Zone methodology, this approach has been removed from the Standard. **The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the "triggers", follow up activities, and procedures that best fit its situation. The SDT feels this is a better approach than to have a rigid definition of an imminent threat.**		
JEA	Agree	It is appropriate to require procedures to respond to "emergency" conditions; however Imminent Vegetation Threat should be a defined term.
Response: Thank you for your comment. The SDT prefers to allow the verbiage "an imminent threat of a vegetation-related Sustained Outage" to stand without further definition.		
BCTC	Agree	We agree with 1.4, with the following qualification: Any standard that is developed should not contain advisory-type language—it should be declarative in tone. For example, in R1.4, the ending clause that begins "…and may include actions…" should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program.
Response: Thank you for your comment. The advisory type language has been removed from the requirement as you have suggested. The SDT also agrees that these "advisory" actions could fall outside the responsibility of some utilities' Transmission Vegetation Management Program. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation.		
Great River Energy	Agree	GRE agrees and believes that it is very important for the applicable entities to posses an Imminent Threat Procedure. GRE recommends that the Imminent Threat procedure be renamed "Vegetation Imminent Threat Procedure" so as to clearly identify the procedure in the event that a company has imminent threat procedures for more than one situation.
Response: Thank you for your comment. We agree that many situations can constitute an imminent threat; however, the SDT did not rename the		

Organization	Agree?	Question 7 Comment
overall procedure as you have suggested. It is acceptable to have the imminent threat procedure for this standard included in a larger corporate procedure or set of procedures that address a wider array of threats. Instead the requirement has been rewritten to focus on the main purpose of the imminent threat requirement; which is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation. The SDT feels that this approach allows the Transmission Owner the flexibility to have imminent threat procedures for more than one situation which remain outside the specific requirements of the vegetation Standards.		
Santee Cooper	Agree	
Exelon	Agree	
Central Maine Power Company	Agree	
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
Kansas City Power & Light	Agree	
City of Tallahassee	Agree	
Northern California Power Agency (NCPA)	Agree	
Northern Indiana Public Service Company	Agree	
Long Island power Authority	Agree	
National Grid	Agree	

Organization	Agree?	Question 7 Comment
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
CenterPoint Energy	Agree	
Buckeye Power, Inc.	Agree	

8. Requirement 1 section R1.5 replaces Version 1 sub-requirement R1.4. This section is now referred to as interim corrective action process. This process addresses situations where vegetation maintenance activities cannot be performed as planned. The term corrective action plan is used in lieu of mitigation plan to avoid confusion with other uses in NERC of "mitigation plan". Do you agree with R1.5? If not, please explain.

Summary Consideration: Many of the stakeholders asked about the use of the word "interim" in R1.5 and what a constraint is. The SDT explains that 1.3 of the version 2 standard is intended to allow Transmission Owners to adjust the annual work plan to reflect such changes as a long term fix. Part 1.5 is intended to address an interim constraint such as customer refusals, governmental agency imposed restrictions, etc. To help clarify, the SDT added the word "temporarily" to the language noted in requirement R1.5. The SDT also added a new requirement R1.6 to address long term strategies.

1.5 Specify an interim corrective action process for use when the Transmission Owner is temporarily constrained from performing vegetation maintenance as planned.

1.6 Specify the maintenance strategies used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that Table 1 clearances in Attachment 1 are never violated. The maintenance strategies shall consider the sag and sway of the conductor throughout its operating range under rated conditions.

Organization	Agree?	Question 8 Comment
Western Area Power Administration, Rocky Mountain Region		The specifics of a "plan" as required by R1.4 in version 1 of the Standards has been replaced with the generalities of a "process" required by R1.5 in version 2 of the Standards. At the time of an audit, the adequacy of a general process is harder to measure than the adequacy of the specific mitigation measures that were previously required by R1.4 in version 1 of the Standards. It is unclear what an auditor will be looking for to determine compliance with R1.5 - will the auditor be looking for generalities or specifics? Further, if a utility has documented their interim corrective action process, but it is not followed, is this a violation of the Standards?
Response: Thank you for your comments. The SDT intended to require a documented process for Transmission Owners to develop plans which address instances such as customer refusals, government agency imposed constraints, etc. It is not intended solely for situations where initial desired clearances could not be achieved (as in requirement R1.4 of version 1 of FAC-003). The measure for Interim Corrective Action requires it be included in the Transmission Vegetation Management Program and failure to do so would be a violation.		
City of Tallahassee	Disagree	The use of the term "interim corrective action" implies that a permanent solution or return to the original plan must be pursued. I would change this to "alternate maintenance" process to prevent non-compliance if the Transmission Owner is constrained and has reached an agreement with the land owner that works to maintain

Organization	Agree?	Question 8 Comment
		the reliability of the line.
Response: Thank you for your comment. Requirement R1, Part 1.5 requires the Transmission Owner to specify a process in its Transmission Vegetation Management Program that the Transmission Owner may use when vegetation maintenance work is temporarily constrained. Constraints may include temporary situations such as caused by customer refusals, governmental agency imposed restrictions, etc. If a Transmission Owner reaches an agreement for "alternate maintenance" in these situations, Requirement R1,Part 1.3.3 allows for adjustment of the annual work plan. Alternative maintenance actions as suggested are now addressed in new Requirement R1,Part 1.6 as noted above in the consideration of comments to address long term maintenance strategies to ensure Table 1 clearance distances are never violated.		
Northern Indiana Public Service Company	Disagree	The existing R1.4 is focused on identifying where vegetation clearance objectives cannot be met at the time UVM work is performed due to restrictions outside of the Transmission Owner's immediate control. The proposed revised standard is focused on situations where work scheduled in the annual plan cannot be performed as planned for any reason. Can a constraint on planned work be internal such as budget related? Why bother with a corrective process for constrained planned work if the work not completed as planned poses no risk of causing an outage? I strongly believe that the sole focus of this provision must specifically address individual locations where, due to restrictions outside of the Transmission Owner owner's control, vegetation clearances specified in the Transmission Vegetation Management Program cannot be obtained. This section of the standard should be about trees being closer to conductors than they should be due to factors beyond the Transmission Owner's control, rather than whether or not planned work was performed.
Response: Thank you for your comments. Interim corrective actions are intended to address situations such as customer refusals, governmental agency imposed constraints, etc. Requirement R1, Part 1.3 requires that the annual work plan shall be documented and Requirement R1, Part 1.3.3 permits adjustments to the annual work plan. A Requirement R1, Part 1.6 was added to address long term maintenance strategies to ensure Table 1 clearance distances are never violated.		
Tampa Electric Company	Disagree	The phrasing above references a "corrective action plan". However, the standard as written is stated as an "interim corrective action process". These are not one and the same. Interim implies a truly temporary condition. As described on page 21 of the Technical reference, however, some of these operational issues may not be "interim".
Response: Thanks for your comments. The SDT agree that "interim" should have been included in the question. The Technical Reference document does not appear to be in conflict with this. To add clarity the SDT added the word temporarily to Requirement R1, Part 1.5 and long term strategies are addressed in new Requirement R1, Part 1.6 a to address long term maintenance strategies to ensure Table 1 clearance distances are never violated.		
Manitoba Hydro	Disagree	Agree with the change in terminology - but would suggest that wording clarify that this is not only for situations where the utility is unexpectedly prevented from implementing its annual plan - but also for areas where it is

Organization	Agree?	Question 8 Comment
		unable to implement its clearance requirements due to property rights limitations.
Response: Thank you for your comment. Requirement R1, Part 1.5 requires the Transmission Owner to specify a process in its Transmission Vegetation Management Program that the Transmission Owner may use when vegetation maintenance work is <u>temporarily</u> constrained. Constraints may include temporary situations such as caused by customer refusals, governmental agency imposed restrictions, etc. Requirement R1, Part 1.6 was added to address long term maintenance strategies to ensure Table 1 clearance distances are never violated.		
National Grid	Disagree	National Grid agrees replacing mitigation plan with corrective action process. However, National Grid questions the use of "interim" for a corrective action process in R1.5, and suggests striking "interim".
Response: Thank you for your comment. Requirement R1, Part 1.5 requires the Transmission Owner to specify a process in its Transmission Vegetation Management Program that the Transmission Owner may use when vegetation maintenance work is <u>temporarily</u> constrained. Constraints may include temporary situations such as caused by customer refusals, governmental agency imposed restrictions, etc. To add clarity the SDT added the word "temporarily" to Requirement R1, Part 1.5.		
CenterPoint Energy	Disagree	Since there is no longer a reference to defined clearances in the Standard, it is unclear under what specific "constrained" conditions R1.5 applies. R1.5 does not have a sister requirement for implementation within the Standard which implies it has a diminished value. R1.5 and M1.5 should be deleted as a requirement and measure, but should be footnoted as best practice as was ANSI A300 in R1.1.
Response: Thank you for your comments. The SDT intended to require a documented process for Transmission Owners to develop plans which address instances such as customer refusals, government agency imposed constraints, etc. It is not intended solely for situations where initial desired clearances could not be achieved (as in requirement R1.4 of version 1 of FAC-003). A new Requirement R1, Part1.6 was added to address long term maintenance strategies to ensure Table 1 clearance distances are never violated.		
American Transmission Company	Agree	ATC agrees with the concept but disagrees with the proposed language. ATC believes the term "interim" should be removed from R 1.5. In some cases, a corrective action can end up being a long term/normal fix. Proposed Language: Specify a corrective action process that will be used when established clearances or methodologies are altered.
Response: Requirement R1, Part 1.3 requires that the annual work plan shall be documented. Requirement R1, Part 1.3.3 permits adjustments to the annual work plan. A long term fix would be an adjustment to the annual work plan. In Requirement R1, Part 1.5, the SDT intended to require a documented process for Transmission Owners to develop plans which address instances such as customer refusals, government agency imposed constraints, etc. It is not intended solely for situations where initial desired clearances could not be achieved (as in requirement R1.4 of version 1 of FAC-003). To add clarity the SDT added the word "temporarily" to Requirement R1, Part 1.5. Long term strategies are addressed in new requirement R1.6 as noted above in the consideration of comments to address long term maintenance strategies to ensure Table 1 clearance distances are never		

Organization	Agree?	Question 8 Comment
violated.		
Southern California Edison Company	Agree	Q8: SCE agrees in part with the revisions to R1.5, including the proposed phrase "corrective action process". However, we do not believe it is necessary to include the term "Transmission Owner" in the sentence because the entire standard is clearly applicable to Transmission Owners. SCE respectfully suggests that proposed R1.5 be revised to read: "Specify an interim corrective action process for use when planned vegetation maintenance is deterred."
Response: Thank you for your comment. The SDT considered your suggested language and feels the language used in the draft standard is appropriate in order to maintain consistency with other parts of the standard.		
Western Utility Arborists	Agree	Yes, we agree.
Response: Thank you for your participation.		
FirstEnergy	Agree	We agree with the concept of a corrective action plan. However, it is not clear what flexibility the Transmission Owner is afforded in making adjustments to the work plan that may carry over from one calendar year to the next. Legal issues with property owners or other factors may prevent the utility from carrying out the work plan as scheduled. Also, we question the use of the term "constrained". It should be clear as to what constitutes appropriate or valid constraints.
Response: Thank you for your comments. Requirement R1, Part 1.3.3 permits adjustments to the annual work plan. As to your next concern, Requirement R1, Part 1.5 requires the Transmission Owner to specify a process in its Transmission Vegetation Management Program that the Transmission Owner may use when vegetation maintenance work is temporarily constrained. Constraints may include temporary situations such as caused by customer refusals, governmental agency imposed restrictions, etc. Refer to the Technical Reference document for additional information.		
MRO NERC Standards Review Subcommittee	Agree	The MRO believes that the term "interim" should be removed from R1.5. The term Interim is subjective.
Response: Thank you for your comment. The SDT uses “interim” to convey the temporary nature of these situations. To add clarity the SDT added the word “temporarily” to Requirement R1. Part 1.5 and a new Requirement R1, Part 1.6 was added to address long term maintenance strategies to ensure Table 1 clearance distances are never violated.		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 8
Response: Thank you for your participation.		

Organization	Agree?	Question 8 Comment
Platte River Power Authority	Agree	The term corrective action plan adds clarity.
Response: Thank you for your participation.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	In my opinion, problems between the Transmission Owner and the USFS over the Transmission Vegetation Management Program should be worked out before a Transmission Vegetation Management Program is ever finalized. A dispute resolution process outside the control of either party would be very helpful and would probably facilitate quicker solutions than if the Transmission Owner and the USFS are left to work out problems on their own. If a Transmission Vegetation Management Program is prepared in a vacuum, the problems may not come to light until some kind of outage actually occurs. It would be much better to flush any disagreements and deal with them before any outages actually occur.
Response: Thank you for your comment. We agree with the sentiment of collaboration and cooperation expressed. We are somewhat constrained by the types of entities that must be subject to this standard. The USFS, as a government agency, is not under the purview of the FERC and is not compelled to comply with this standard however well intended. The SDT would support a dispute resolution process that resolves potential disagreements consistent with the purpose of this standard.		
BCTC	Agree	Yes, we agree.
Response: Thank you for your participation.		
Great River Energy	Agree	GRE believes that the term "interim" should be removed from R1.5. The term Interim is subjective.
Response: Thank you for your comment. Requirement R1, Part 1.5 requires the Transmission Owner to specify a process in its Transmission Vegetation Management Program that the Transmission Owner may use when vegetation maintenance work is temporarily constrained. Constraints may include temporary situations such as caused by customer refusals, governmental agency imposed restrictions, etc. To add clarity the SDT added the word temporarily to Requirement R1, Part 1.5 and long term strategies are addressed in new Requirement R1, Part1.6 to address long term maintenance strategies to ensure Table 1 clearance distances are never violated.		
Progress Energy Carolinas	Agree	
Associated Electric Cooperative Inc.	Agree	
NPCC	Agree	

Organization	Agree?	Question 8 Comment
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
SERC Vegetation Management Subcommittee (VMS)	Agree	
Progress Energy Florida	Agree	
Kansas City Power & Light	Agree	
SERC OC Standards Review Group	Agree	
Florida Power & Light	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
Bonneville Power Administration	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	

Organization	Agree?	Question 8 Comment
Exelon	Agree	
Central Maine Power Company	Agree	
American Electric Power (AEP)	Agree	
Northern California Power Agency (NCPA)	Agree	
Orange and Rockland Utilities Inc.	Agree	
Ameren	Agree	
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Consumers Energy Company	Agree	
Pacific Gas & Electric Co.	Agree	
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	
San Diego Gas & Electric	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	

Organization	Agree?	Question 8 Comment
WECC	Agree	
Arizona Public Service Company	Agree	
Baltimore Gas & Electric Company	Agree	
Duke Energy Corporation	Agree	
Entergy Services	Agree	
Pepco Holdings, Inc	Agree	
JEA	Agree	
Independent Electricity System Operator	Agree	
Salt River Project	Agree	
Northeast Utilities	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
Buckeye Power, Inc.	Agree	

9. Clearance 1 in Version 1 was a "fill-in-the-blank" requirement and was removed from the standard. Do you agree? If not, please explain.

Summary Consideration: Most of the industry comments are in favor of removing the "fill-in-the-blank" requirement. Some disagreed, citing the benefit of having perceived leverage that a Clearance 1 afforded them. The SDT points out that ANSI A300 remains a "best practice" referenced in the proposed standard and may be useful in dealing with public and private parties. In addition, the SDT added Requirement R1.6:

1.6 Specify the maintenance strategies used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that Table 1 clearances in Attachment 1 are never violated. The maintenance strategies shall consider the sag and sway of the conductor throughout its operating range under rated conditions.

The SDT believes that Clearance 1 may be unnecessarily restrictive in stipulating conductor-to-vegetation distances (as some commenters have done to comply) and therefore removed Clearance 1 in favor of Requirement R1, Part 1.6. which specifically allows for vegetation-to-ground distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions.

Organization	Agree?	Question 9 Comment
Florida Power & Light		FPL neither agrees or disagrees with this removal but provides the following comment. FPL's experience regarding Clearance 1 is that it was an effective way of demonstrating a measurable requirement for compliance when dealing with public entities. The use of a corrective action process to mitigate instances where this clearance was not met before violations occurred is also very effective in promoting reliability and safety in the Standard.
Response: Thank you for your comment. The SDT team acknowledges the comment with regard to the usefulness of Clearance 1 in dealing with public entities and has attempted to retain that capability in Requirement R1, Part 1.6. Furthermore the use of a corrective action process is retained in this latest version but is renamed as an "interim correction action" in lieu of "Mitigation Plan" to avoid confusion with a Compliance Program term.		
Western Utility Arborists	Disagree	The Western Utilities do not agree with the removal of Clearance 1. We recommend adding it back to the document, but reworded and moved to include it as a measurement (M), rather than a requirement (R) under the new standard. Many utilities feel that Clearance 1 provides justification and leverage for operational clearances when dealing with organizations such as municipalities. Without Clearance 1, utilities could be mandated in specific situations to clear so that the vegetation is just beyond the Critical Clearance Zone at all times. This could result in pruning at six month intervals, which is not feasible or cost-effective.

Organization	Agree?	Question 9 Comment
Response: Thank you for your comment. The SDT notes that information contained in a Measure would not be mandatory nor enforceable and therefore has minimal usefulness as leverage. The SDT points out that ANSI A300 remains a "best practice" referenced in the proposed standard and may be useful in dealing with the public and private parties. The addition of Requirement R1, Part 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		
Bonneville Power Administration	Disagree	BPA opposes removal of Clearance 1. Clearance 1 provides a regulatory justification for a Transmission Owner to apply and extend proactive vegetation threat prevention programs on its rights of way easements across municipal, state, tribal, other federal and private properties. In many cases, without the regulatory leverage of a Clearance 1 requirement, Transmission Owners would be limited to maintaining less effective and higher risk vegetation management practices where it has legal restrictions, then it presently can implement under the present version of FAC 003-01. BPA recommends that Clearance 1 be placed back into the document, but as a Measure and not a Requirement.
Response: Thank you for your comment. The SDT notes that information contained in a Measure would not be mandatory nor enforceable and therefore has minimal usefulness as leverage. The SDT points out that ANSI A300 remains a "best practice" referenced in the proposed standard and may be useful in dealing with the public and private parties. The addition of Requirement R1, Part 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		
Exelon	Disagree	We do not understand the reference to "fill in the blank" requirement for clearance 1. As commonly understood, a "fill in the blank" standard /requirement is one that was assigned to the RRO. Clearance 1 in FAC-003-1 is a Transmission Owner requirement. The reference to a clearing zone should be retained, as each Transmission Owner will need to define this in their program so as to avoid encroachments into the Critical Clearance Zone .
Response: Thank you for your comment. The choice of a Clearance 1 distance is left to each Transmission Owner and as such is characterized as a fill-in-the blank style requirement. The SDT team believes each Transmission Owner is free to set any working distances it deems appropriate in order to accomplish its Transmission Vegetation Management Program objectives.		
Central Maine Power Company	Disagree	Central Maine Power Company disagrees with removal of clearance 1. The clearance 1 was included so that professional arborists could establish the clearance necessary for a transmission owner to reduce the risk of a tree caused power outage. The transmission owner should use ANSI- Standard A300, including PART 7, and other publications to develop best management practices which include clearances at time of maintenance. Clearance 1 provides leverage for Transmission Owners to achieve the clearances stated in their Transmission

Organization	Agree?	Question 9 Comment
		Vegetation Management Program.
Response: Thank you for your comment. The SDT notes that information contained in a Measure would not be mandatory nor enforceable and therefore has minimal usefulness as leverage. The SDT points out that ANSI A300 remains a "best practice" referenced in the proposed standard and may be useful in dealing with the public and private parties. The addition Requirement R1, Part 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Disagree	If it is possible for NERC to identify minimum clearance standards as related to arcing potential for hazardous vegetation, it would definitely help USFS field administrators to have some kind of hard and fast standards. If that kind of approach is not reasonable in light of the need to adjust standards for various load conditions and vegetation growth rates, then a prescribed formula for calculating minimum clearances would be the next best thing.
Response: Thank you for your comment. The SDT proposes the table of Minimum Vegetation Clearance Distances in this revised version of the standard in Requirement R4, which prohibits vegetation encroachment inside minimum vegetation clearance distances that are developed with Gallet equations for flashover (arcing).		
National Grid	Disagree	National Grid takes exception to the term "fill-in-the-blank". National Grid disagrees with the elimination of Clearance 1. The Clearance 1 requirement in FAC-003-1 was meant to allow a Transmission Owner to establish clearances to be achieved at the time of vegetation management work, and be sensitive to local and regional conditions. National Grid believes that Clearance 1 is needed for public education and safety reasons. Clearance 1 standards allow utilities to specify a cyclic programmatic approach, and gives the utility leverage with local and state regulators and the public to achieve significantly larger than minimal clearances.
Response: Thank you for your comment. The choice of a Clearance 1 distance is left to each Transmission Owner and as such is characterized as a fill-in-the blank style requirement. The SDT team believes each Transmission Owner is free to set any working distances it deems appropriate in order to accomplish its Transmission Vegetation Management Program objectives. The SDT points out that ANSI A300 remains a "best practice" referenced in the proposed standard and may continue to be useful in dealing with the public and private parties. The addition of Requirement R1, Part 1.6 allows for vegetation-to-ground working distances which can be larger than minimal clearances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		

<table>
<tr><th>Organization</th><th>Agree?</th><th>Question 9 Comment</th></tr>
<tr><td>Platte River Power Authority</td><td>Disagree</td><td>Clearance 1 could be defined in the standard in tables developed using IEEE Standards for various voltages, line spans and altitudes. Clearance 1 provides justification and leverage for operational clearances when dealing with organizations such as municipalities. Without Clearance 1, utilities could be mandated in specific situations to clear so that the vegetation is just beyond the Critical Clearance Zone at all times. This could result in pruning at six month intervals, which is not feasible or cost-effective.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. The SDT proposes the table of Minimum Vegetation Clearance Distances in this revised version of the standard in Requirement R4, which prohibits vegetation encroachment inside minimum vegetation clearance distances that are developed with Gallet equations for flashover (arcing). The SDT points out that the ANSI A300 remains a "best practice" referenced in the proposed standard and may be useful in dealing with the public such as municipalities and private parties. The addition of Requirement R1, Part 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.</td></tr>
<tr><td>Northern Indiana Public Service Company</td><td>Disagree</td><td>I am strongly opposed to the removal of Clearance 1 from the standard. Being able to point to this provision has been invaluable to internal communications with upper management and external discussions with land owners and the public concerning UVM. In fact, other than the patrol/inspection requirements, no other provision in the standard has been as essential to preventing grow-in tree contacts than Clearance 1. It has forced Transmission Owner's across the country to re-claim overgrown ROW and re-commit to consistent UVM practices. We all know how easy it is for Transmission Owner's to get weak in the knees in the face of public opposition to proper and prudent UVM work even when it is clear what needs to be done. This dynamic is what led us to the 2003 blackout to begin with. I would like to see the drafting team consider expanding upon the existing model and create three clearances:

1. A clearance at the time work is performed,

2. An action threshold clearance which would trigger the Transmission Owner would take immediate action to clear encroaching vegetation posing an unacceptable outage risk, and

3. A no closer than clearance in which vegetation would never be allowed to encroach in order to prevent flashover.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. The SDT team acknowledges the comment with regard to the usefulness of Clearance 1 to internal communications and in dealing with public entities and has attempted to retain that capability Requirement R1. Part 1.6. The addition of Requirement R1, Part 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.</td></tr>
</table>

Organization	Agree?	Question 9 Comment
In regard to working distances or as you put it , each Transmission Owner continues to able to set any working distances it deems appropriate in order to accomplish its Transmission Vegetation Management Program objectives when complying with Requirement R1, Part 1.6. **With respect to your 3rd comment, the proposed version of the standard has Requirement R4, which prohibits vegetation encroachment inside Minimum Vegetation Clearance Distances that are developed with Gallet equations for flashover.**		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Disagree	We do not agree with the removal of Clearance 1. We recommend adding it back to the document, but reworded and moved to include it as a measurement (M), rather than a requirement (R) under the new standard. Many utilities feel that Clearance 1 provides justification and leverage for operational clearances when dealing with organizations such as municipalities. Without Clearance 1, utilities could be mandated in specific situations to clear so that the vegetation is just beyond the Critical Clearance Zone at all times. This could result in pruning at six month intervals, which is not feasible or cost-effective.
Response: Thank you for your comment. The SDT notes that information contained in a Measure would not be mandatory nor enforceable and therefore has minimal usefulness as leverage. The SDT points out that ANSI A300 remains a "Best Practice" referenced in the proposed standard and may be useful in dealing with the public and private parties. The addition of Requirement R1, Part 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		
San Diego Gas & Electric	Disagree	We do not agree with the removal of Clearance 1. We recommend that it be added back into the document, but reworded and moved so it be included as a measurement, rather than a requirement. Without Clearance 1, utilities could be mandated in specific situations to clear so that vegetation is just beyond the Critical Clearance Zone at all times, which is not feasible or cost effective.
Response: Thank you for your comment. The SDT notes that information contained in a Measure would not be mandatory nor enforceable and therefore has minimal usefulness as leverage. The SDT points out that ANSI A300 remains a "Best Practice" referenced in the proposed standard and may be useful in dealing with the public and private parties. The addition of Requirement R1, Paart 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		
Hydro One Networks Inc.	Disagree	We would agree only if the standard is revised to include the removal of incompatible vegetation as outlined in our response to question 3 above. If not, then added direction or requirements are needed to introduce the elements that combine (to a greater degree than exists under the revised standard) reliability and vegetation management. Clearance 1 accomplished this to some degree.

Organization	Agree?	Question 9 Comment
Response: Thank you for your comment. The SDT considered the insertion of the phrase “incompatible vegetation” however decided against it because incompatibility may be arguable and add to disagreement among interested parties. The SDT agrees with the commenter that all vegetation that is identified by the annual work plans and maintenance strategies should be targeted for removal. Each Transmission Owner is free to use any effective approach it deems appropriate in order to accomplish its Transmission Vegetation Management Program objectives. The proposed version of the standard has Requirement R4, which prohibits vegetation encroachment inside Minimum Vegetation Clearance Distances that are developed with Gallet equations for flashover.		
Arizona Public Service Company	Disagree	APS disagrees with removal of clearance one. Clearance one should be achieved at time of maintenance which is part of the vegetation program. This gives leverage with dealing with state and federal agencies, tribal and private landowners. This isn't a fill in the blank requirement, however it should be based on sound science in regards to vegetation management. A professional arborist/forester can determine the appropriate amount of vegetation that needs to be obtained at the time of maintenance. APS suggest the following language change for clearance 1. The Transmission Owner shall maintain ROW on Federal, State, Tribal and Private lands in accordance with ANSI-Standard A300 (Part 1)-2001 and (Part 7)-2006 in consultation with companion publication Best Management Practices: Integrated Vegetation Management, 2007. If all utilities followed this standard this would increase the reliability of the bulk electric system and reduce the risk of vegetation outages.
Response: Thank you for your comment. The SDT agrees that any requirement must be based on sound science and believes the Transmission Owner will continue to able to set any working distances it deems appropriate in order to accomplish its Transmission Vegetation Management Program objectives when complying with Requirement R1, Part 1.6. The stipulation that the Standard applies to Federal, State, Tribal and Private Lands is contained in the Applicability section. The SDT points out that ANSI A300 remains a “best practice” referenced in this standard and as such may be useful in dealing with state and federal agencies, tribal and private landowners, etc.		
BCTC	Disagree	BCTC do not agree with the removal of Clearance 1. We recommend adding it back to the document, but reworded and moved to include it as a measurement (M), rather than a requirement (R) under the new standard. Many utilities feel that Clearance 1 provides justification and leverage for operational clearances when dealing with organizations such as municipalities. Without Clearance 1, utilities could be mandated in specific situations to clear so that the vegetation is just beyond the Critical Clearance Zone at all times. This could result in pruning at six month intervals, which is not feasible or cost-effective.
Response: Thank you for your comment. The SDT notes that information contained in a Measure would not be mandatory nor enforceable and therefore has minimal usefulness as leverage. The SDT points out that ANSI A300 remains a ”best practice” referenced in the proposed standard and may be useful in dealing with the public and private parties. The addition of Requirement R1, Part 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		

Organization	Agree?	Question 9 Comment
Salt River Project	Disagree	Recommend adding it back to the document, however, only if it is changed to become a measurement (M) rather than a requirement (R). Leaving it in as a measurement provides justification and leverage for operational clearances when dealing with landowners. Without Clearance 1 landowners may only allow vegetation clearance just at the Critical Clearance Zone at all times, which is not a feasible, cost-effective, or responsible way for utilities to manage vegetation clearance.
Response: Thank you for your comment. The SDT notes that information contained in a Measure would not be mandatory nor enforceable and therefore has minimal usefulness as leverage. The SDT points out that ANSI A300 remains a "best practice" referenced in the proposed standard and may be useful in dealing with the public and private parties. The addition of Requirement R1, Part 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		
American Electric Power (AEP)	Agree	AEP agrees with the removal of Clearance 1 from the Standard.
Response: Thank you for your comment.		
NPCC	Agree	We agree but believe that the Transmission Vegetation Management Program should target removal of all incompatible vegetation on the Active Right of Way as described in the response to question 3.
Response: Thank you for your comment. The SDT agrees with the commenter that any vegetation located within the Active Transmission Line ROW should be targeted for removal using means and strategies described in its Transmission Vegetation Management Program.		
Western Area Power Administration, Upper Great Plains Region	Agree	While Western (UGPR) agrees with the removal of Clearance 1, we believe it is advantageous for Transmission Owners to have a "trigger distance" in order to have some additional time to plan and schedule vegetation work. The trigger distance is advantageous only if the Regulators do NOT interpret it to be an extended Critical Clearance Zone and do NOT enforce based on "trigger distance" instead of the Critical Clearance Zone .
Response: Thank you for your comment. The SDT team believes the addition of Requirement R1, Part 1.6 continues to allow each Transmission Owner to set any working distances it deems appropriate in order to accomplish the objectives with this Standard. This Requirement 1 Part 1.6 is superior to Clearance 1 as it gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		
MRO NERC Standards Review Subcommittee	Agree	The MRO agrees and fully supports the removal of Clearance 1. The MRO believes that the Gallet equation is a more effective way of determining the required clearances.

Organization	Agree?	Question 9 Comment
Response: Thank you for your comment.		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 9
Response: Thank you for your comment.		
Orange and Rockland Utilities Inc.	Agree	We generally agree, however please see comments included in question 18.
Response: Thank you for your comment.		
Baltimore Gas & Electric Company	Agree	While I may agree with the removal of this requirement strictly for reasons of simplification and self-determination, the current requirement forced utilities to structure their Transmission Vegetation Management Program to develop safeguards to keep trees from encroaching into the Clearance 2 envelope. The proposed change will leave the clearance issue beyond the Critical Clearance Zone unaddressed. Responsible utilities will take the appropriate measures and other utilities will not.
Response: Thank you for your comment. Each Transmission Owner is free to use any effective approach it deems appropriate in order to accomplish its Transmission Vegetation Management Program objectives. The SDT believes there are significant disincentives against the behavior you warn about in the revised version.		
CenterPoint Energy	Agree	Designation of Clearance 1 is not required to meet the purpose of the Standard.
Response: Thank you for your comment.		
Hydro-Quebec Transenergie (HQT)	Agree	We agree but believe that the Transmission Vegetation Management Program should target removal of all incompatible vegetation on the Active Right of Way as described in the response to question 3.
Response: Thank you for your comment. The SDT agrees with the commenter that any vegetation that are located within the Active Transmission Line ROW should be targeted for removal using means and strategies described in its Transmission Vegetation Management Program.		
Great River Energy	Agree	GRE agrees and fully supports the removal of Clearance 1. GRE believes that the Gallet equation is a more effective way of determining the required clearances.
Response: Thank you for your comment.		

Organization	Agree?	Question 9 Comment
Southern California Edison Company	Agree	Q9: No comments.
Associated Electric Cooperative Inc.	Agree	
WECC Reliability Coordination	Agree	
SERC Vegetation Management Subcommittee (VMS)	Agree	
Progress Energy Florida	Agree	
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Progress Energy Carolinas	Agree	
SERC OC Standards Review Group	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
FirstEnergy	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	

Organization	Agree?	Question 9 Comment
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	
City of Tallahassee	Agree	
Northern California Power Agency (NCPA)	Agree	
Tampa Electric Company	Agree	
American Transmission Company	Agree	
Ameren	Agree	
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Manitoba Hydro	Agree	
Consumers Energy Company	Agree	
Pacific Gas & Electric Co.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Entergy Services	Agree	

Organization	Agree?	Question 9 Comment
Pepco Holdings, Inc	Agree	
JEA	Agree	
Northeast Utilities	Agree	
Independent Electricity System Operator	Agree	
Duke Energy Corporation	Agree	
Buckeye Power, Inc.	Agree	

10. Personnel Qualifications in R1.3 in Version 1 was a "fill-in-the-blank" requirement and was removed from Version 2 of the standard. Do you agree? If not please explain.

Summary Consideration: Most commenters agree with the deletion of R1.3 from the approved standard. The" fill in the blank" requirement that was included in version 1 allowed the Transmission Owner to set its own standard for personnel qualifications rather than require the same set of qualifications for personnel in all entities. The SDT recommended removing the requirement as it is not enforceable and recommended against replacing the "fill-in-the-blank" element with a continent-wide set of personnel qualifications. The SDT believes that any set of personnel qualifications enforced on a continent-wide basis would result in a set of "lowest common denominator" qualifications that would be too stringent for some entities, and too lax for others – with no apparent reliability benefit. Instead, the SDT recommended letting entities set their own internal personnel qualifications to best meet their own needs.

Organization	Agree?	Question 10 Comment
Central Maine Power Company	Disagree	Central Maine Power Company disagrees with the removal of the qualification statement. The individual responsible for this critical program must be qualified through experience, training, and education. The International Society of Arboriculture has a certification program that can help with guidelines for qualified arborists.
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard, remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
Northern Indiana Public Service Company	Disagree	If the standard continues to allow T.O.'s to design and implement their own TVMPs and expect them to use BMPs, ANSI A300, develop methods and practices, adapt schedules and plans to changing conditions, etc., then it is reasonable to expect that T.O. personnel responsible for the TVMP to be experts in the field of utility vegetation management with appropriate training, certifications, licenses and credentials. I do not agree with eliminating this requirement. Quite the opposite, I believe that the requirement needs to be more specific as to minimum qualifications key personnel must meet. There are more requirements & qualifications to drive a semi-truck than to design and implement a program (UVM) critical to the operation of the nation's electric grid. Does that make sense?
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard, remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
USDA Forest Service, Southwestern Region, Regional	Disagree	Perhaps standard M8 could be expanded or clarified to require the Transmission Owner to describe how employees, especially field supervisors, are trained to implement the plan and to prove that the training was

Organization	Agree?	Question 10 Comment
Office for AZ and NM		actually provided. Some problems have arisen in the USFS Southwestern Region because some Transmission Owners are not providing adequate supervision of field work.
Response: The SDT thanks you for your comment. The requirement that was dropped between the version 1 and version 2 spoke to the qualifications of development and implementation of the TVMP and not the adequacy of the field supervision. This does not relieve the TO from providing adequate field supervision.		
National Grid	Disagree	National Grid takes exception to the term “fill-in-the-blank”. National Grid would like Personnel Qualifications to remain in Standard FAC-003-2.
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard, remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
San Diego Gas & Electric	Disagree	We feel there must be appropriate knowledge to do the work, and that Transmission Owners must at least have internal standards related to personnel qualifications.
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard, remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
Arizona Public Service Company	Disagree	APS disagrees with the removal of personnel qualifications. The person responsible for vegetation management program should have experience and training in vegetation management and system operations. The International Society of Arboriculture has an ISA Certified Arborist and Utility Specialist certification. This requires the credential holder to have minimal qualifications before sitting for the certification and on going training to maintain the credential. The industry has already responded by providing the information as part of the current standard FAC-003-1. It makes no sense to remove personnel qualifications from the revision.
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard, remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
British Columbia Transmission Corp.	Disagree	BCTC does not agree with the elimination of this requirement. We feel strongly there must be appropriate knowledge to do the work, and that Transmission Owners must have internal standards related to personnel qualifications. We understand that several utilities would like this requirement removed because it created problems in the auditing process. It is unfortunate that this important requirement for an effective vegetation management program has been removed due misapplication of the intent during audits.
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard,		

Organization	Agree?	Question 10 Comment
remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
Central Maine Power Company	Disagree	Central Maine Power Company disagrees with the removal of the qualification statement. The individual responsible for this critical program must be qualified through experience, training, and education. The International Society of Arboriculture has a certification program that can help with guidelines for qualified arborists.
Response: The SDT thanks you for your response. While we agree that the International Society of Arboriculture certifications are credible qualifications for a large work force, these same programs may be too stringent and unnecessary for utilities only needing a very small work force. **It is unknown if certification by ISA or similar organizations has impacted reliability for any Transmission Owner.**		
Northern Indiana Public Service Company	Disagree	If the standard continues to allow T.O.'s to design and implement their own Transmission Vegetation Management Programs and expect them to use BMPs, ANSI A300, develop methods and practices, adapt schedules and plans to changing conditions, etc., then it is reasonable to expect that T.O. personnel responsible for the Transmission Vegetation Management Program to be experts in the field of utility vegetation management with appropriate training, certifications, licenses and credentials. I do not agree with eliminating this requirement. Quite the opposite, I believe that the requirement needs to be more specific as to minimum qualifications key personnel must meet. There are more requirements & qualifications to drive a semi-truck than to design and implement a program (UVM) critical to the operation of the nation's electric grid. Does that make sense?
Response: The SDT thanks you for your response. The SDT concurs that some Transmission Vegetation Management Programs are highly complex and would require highly trained arborists and vegetation management personnel to develop such programs. However, there are many programs that are substantially less complex and do not require that level of expertise. We feel that utilities with complex programs would by nature acquire appropriately trained personnel to implement their programs.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Disagree	Perhaps standard M8 could be expanded or clarified to require the Transmission Owner to describe how employees, especially field supervisors, are trained to implement the plan and to prove that the training was actually provided. Some problems have arisen in the USFS Southwestern Region because some Transmission Owners are not providing adequate supervision of field work.
Response: The SDT thanks you for your comment. The requirement that was dropped between the version 1 and version 2 spoke to the qualifications of development and implementation of the Transmission Vegetation Management Program and not the adequacy of the field supervision.		
National Grid	Disagree	National Grid takes exception to the term "fill-in-the-blank". National Grid would like Personnel Qualifications

Organization	Agree?	Question 10 Comment
		to remain in Standard FAC-003-2.
Response: The SDT thanks you for your response. A" fill in the blank" requirement as stated in version 1 allowed the Transmission Owner to set its own standard and does not substantively add to the effectiveness of the Standard.		
British Columbia Transmission Corp.	Disagree	BCTC does not agree with the elimination of this requirement. We feel strongly there must be appropriate knowledge to do the work, and that Transmission Owners must have internal standards related to personnel qualifications. We understand that several utilities would like this requirement removed because it created problems in the auditing process. It is unfortunate that this important requirement for an effective vegetation management program has been removed due misapplication of the intent during audits.
Response: The SDT thanks you for your response. A" fill in the blank" requirement as stated in version 1 allowed the Transmission Owner to set its own standard and does not substantively add to the effectiveness of the Standard.		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 10
Response: The SDT thanks you for your response.		
Exelon	Agree	Agree but same comment as above, we do not understand the reference to "fill in the blank" requirement for R1.3. As commonly understood, a "fill in the blank" standard /requirement is one that was assigned to the RRO.
Response: The SDT thanks you for your response. A" fill in the blank" requirement as stated in version 1 allowed the TO to set its own standard as opposed to RRO. In either case the concept of a "fill in the blank requirement" does not substantively add to the effectiveness of the Standard.		
Tampa Electric Company	Agree	While we agree with the removal of "fill-in the blank" requirements, we recommend the inclusion of professional qualifications for staff involved in this Standard. Reading the 42 page technical reference and the attached comment form, all involved need to really understand the Standard as well as industry practices.
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard, remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
Baltimore Gas & Electric Company	Agree	Similar to the response to no. 9, the end result is what counts and each utility will be responsible and accountable for their actions. Qualifications unlike clearance requirements, are far-removed from results and can easily be left unaddressed in the new std.

Organization	Agree?	Question 10 Comment
Response: The SDT thanks you for your response.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	We are in agreement with the elimination of this requirement, but not without some qualifications. We feel strongly there must be appropriate knowledge to do the work, and that Transmission Owners must at least have internal standards related to personnel qualifications. It is unfortunate that this important requirement for an effective vegetation management program has been removed due to concerns with the auditing program.
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard, remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
CenterPoint Energy	Agree	Designation of Personnel Qualifications are not required to meet the purpose of the Standard.
Response: The SDT thanks you for your response.		
American Electric Power (AEP)	Agree	AEP agrees that the Standard should not stipulate or require personnel qualifications.
Response: The SDT thanks you for your response.		
Platte River Power Authority	Agree	The requirement should be removed because it is a “fill-in-the-blank” requirement. Defining the proper amount of personnel qualifications and training would be too prescriptive for utilities with small vegetation management programs and not prescriptive enough for utilities with large vegetation management programs.
Response: The SDT thanks you for your comments.		
Western Utility Arborists	Agree	The Western Utilities are in agreement with the elimination of this requirement. However, we feel strongly there must be appropriate knowledge to do the work, and that Transmission Owners must at least have internal standards related to personnel qualifications.
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard, remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
Southern California Edison Company	Agree	Q10: No comments.
SERC OC Standards Review	Agree	

Organization	Agree?	Question 10 Comment
Group		
Florida Power & Light	Agree	
Santee Cooper	Agree	
Progress Energy Carolinas	Agree	
SERC Vegetation Management Subcommittee (VMS)	Agree	
Progress Energy Florida	Agree	
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
City of Tallahassee	Agree	
Northern California Power Agency (NCPA)	Agree	
Long Island power Authority	Agree	
Manitoba Hydro	Agree	
Consumers Energy Company	Agree	
Pacific Gas & Electric Co.	Agree	
Duke Energy Corporation	Agree	
Associated Electric Cooperative	Agree	

Organization	Agree?	Question 10 Comment
Inc.		
NPCC	Agree	
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
Orange and Rockland Utilities Inc.	Agree	
American Transmission Company	Agree	
Ameren	Agree	
Nebraska Public Power District	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Entergy Services	Agree	
Pepco Holdings, Inc	Agree	
JEA	Agree	

Organization	Agree?	Question 10 Comment
Independent Electricity System Operator	Agree	
Salt River Project	Agree	
Northeast Utilities	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
Buckeye Power, Inc.	Agree	
Great River Energy	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
Bonneville Power Administration	Agree	
FirstEnergy	Agree	
MRO NERC Standards Review Subcommittee	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	

11. The IEEE 516 standard distances were replaced with the Gallet equation distances. Clearance 2 was replaced by the Critical Clearance Zone. The Critical Clearance Zone is defined as the zone of all possible positions of the conductor at the line's designed operating ratings including wind factors. (Please refer to pages 22-32 in the Technical Reference Document on the Critical Clearance Zone for further background for this question.) The imminent threat procedure, R2, requires action to be taken to prevent an outage when the Critical Clearance Zone is approached. Do you agree with R2? If not please explain.

Summary Consideration: The majority of responders (61%) disagreed with the concept of the imminent threat procedure being associated with the Critical Clearance Zone (CCZ). The key concerns that commenters raised were associated with the Critical Clearance Zone and included the following:

- It is a good concept but is theoretical and difficult to administer in the field
- Respondents preferred a more defined distance that is real-time and measurable
- The word "approach" caused concern due to being vague and open to interpretation

Although there was no clear minority view, a number of respondents recommended eliminating R2 or R4 because of practical difficulties associated with the CCZ and their belief that R5, R6, and R7 were sufficient to achieve reliability

In response, the SDT modified R2 so that it does not use the CCZ to trigger the imminent threat procedure implementation. R2 now requires the Transmission Owner to implement its imminent threat procedure when it has knowledge of such a threat obtained through normal operating procedures. The SDT decided not to be prescriptive in the definition of a vegetation imminent threat. Rather, the Transmission Owner should have the flexibility of defining its own procedure per the TVMP. In addition R4 has been modified and now requires the Transmission Owner to prevent vegetation encroachment of the Minimum Vegetation Clearance Distances (MVCD) as observed in real time and eliminates the use of the CCZ for this purpose.

R2. Each Transmission Owner shall implement its imminent threat procedure when the Transmission Owner has actual knowledge of such a threat, obtained through normal operating practices.

Deleted: or notification from others, that the Critical Clearance Zone is approached by vegetation to prevent an encroachment of the Critical Clearance Zone.

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Organization	Agree?	Question 11 Comment
BCTC		BCTC feels that changing to the Gallet equation will not have a large impact on its vegetation management operations, so we have no concerns. We agree with R2, but feel that this clause makes R4 redundant, as per our discussion under Comment # 15 below. We recommend the removal of R4 entirely from the standard.

Organization	Agree?	Question 11 Comment
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Western Utility Arborists		The Western Utilities feel that changing to the Gallet equation will not have a large impact on its vegetation management operations, so we have no concerns. We agree with R2, but feel that this clause makes R4 redundant, as per our discussion under Comment # 15 below. We recommend the removal of R4 entirely from the standard.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Associated Electric Cooperative Inc.	Disagree	The phrase “Critical Clearance Zone is approached” in R2 is nebulous and probably unenforceable. The determination and visualization of the Critical Clearance Zone and approaching vegetation encroachment, under field conditions, is a practice in application of theoretical conductor locations in real time. Would the Transmission Owner be found in noncompliance if evidence showed vegetation had “approached” within 20 feet, 2 feet, 2 inches or some other arbitrary distance of the CCZ and the TO failed to implement its imminent threat procedure?
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Western Area Power Administration, Upper Great Plains Region	Disagree	The CCZ as defined would very specifically outline a zone that needs to remain clear of vegetation to avoid a violation, but that specificity could be an overly burdensome concept to implement and/or monitor. Theoretically, there could be an infinite number of allowable vertical and horizontal (for outside phases) clearances depending on your location within each span. Theoretically, you may need to clear cut at mid-span (depending on retreatment intervals, growth rate, etc.) while allowing a 40 foot tree closer to the structure, along with everything in between depending on your location within the span. To fully comply with the CCZ as defined, each Transmission Owner would have to have a table of allowable vertical and horizontal clearances for every few feet on every available span length within each line section. Producing such tables

Organization	Agree?	Question 11 Comment
		would be a significant burden to each Transmission Owner, but without them, the Transmission Owner could not verify that vegetation had not encroached within the CCZ. In order to produce the tables outlined above, the Transmission Owner would need to identify what design parameter(s) are applicable for the "correct" CCZ? We remain concerned that weather conditions in excess of those parameters could lead to a vegetation contact/outage and proving that weather conditions were in excess of design criteria would be extremely difficult or impossible for all spans on a lengthy transmission line. It is not uncommon to have weather stations 50 or more miles away from points on our transmission system. In order to certify/verify compliance, the Transmission Owner would have to physically take their table to the field and verify vertical and horizontal clearances from the edge of the theoretical envelope (not the actual conductor position) for all vegetation within the span. This would be a time-consuming, burdensome, cumbersome process if Regulators are going to require specific evidence in order for the Transmission Owner to document their annual certification.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
SERC Vegetation Management Subcommittee (VMS)	Disagree	The SERC VMS recommends that R2 be deleted. Since this is a "zero tolerance" standard any Transmission Owner will remove any discovered threats to prevent outages. While we agree that the implementation of an imminent threat procedure may be a valid concept, visualization of the Critical Clearance Zone (CCZ) and determining an approaching encroachment is a practice in application of theoretical conductor locations in real time.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Progress Energy Florida	Disagree	The Critical Clearance Zone as currently defined is too academic. Implementation of R2 would require field operations staff to determine the theoretical position of the line during inspections to decide whether to engage the imminent threat procedures. The academic/theoretical aspects of the Critical Clearance Zone definition are not practical or enforceable. The criteria for a violation needs to be limited to the position of the conductor in real time.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		

Organization	Agree?	Question 11 Comment
Western Area Power Administration, Rocky Mountain Region	Disagree	As discussed in the Technical Reference document, the CCZ is a complicated theoretical envelope surrounding all rated operating positions of the conductor. Its dynamic shape is constantly changing and is contingent upon location within the span. Calculation of the size and shape of CCZ is based, in part, upon the design parameters of the transmission facility. However, as-built or long term maintenance conditions can often diverge from the original design requirements over time. Ground elevations can also change as a result of man made or natural causes from the original design elevations recorded on plan and profile engineering drawings. Consequently, precise field measurement of the as-built CCZ is extremely problematic and strategies that utilize the calculation of allowable right-of-way tree heights can be hindered by unrecorded deviations from the original design criteria. Allowable tree height strategies also become increasingly more difficult and impractical with increasing extremes in terrain. While the CCZ is a very important concept for an effective vegetation management program it is far to theoretical, dynamic, and impractical to field measure for use as a clear and precise boundary for regulatory purposes. In addition, the R2 requirement for action when the imprecise and theoretical CCZ boundary is "approached" by vegetation is an even more subjective and unmeasurable. The "rate of approach" is really the key issue of concern. The rate of vegetation approach is a function of many variables including species type and site specific growing conditions. For example, a Century Plant which can grow six inches a day is obviously a much greater concern than a Lodgepole Pine on a dry mountain top which grows only a few inches a year. As such, there is no practical way to define or measure for regulatory purposes those "approach" situations that legitimately require immediate action from those "approach" situations that do not. The wording and concepts of R2 are therefore to imprecise to be used as clear requirements for Standards compliance.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Progress Energy Carolinas	Disagree	The Critical Clearance Zone as currently defined is too academic. Implementation of R2 would require field operations staff to determine the theoretical position of the line during inspections to decide whether to engage the imminent threat procedures. The academic/theoretical aspects of the Critical Clearance Zone definition are not practical or enforceable. The criteria for a violation needs to be limited to the position of the conductor in real time.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
SERC OC Standards Review	Disagree	The SERC OCSRG recommends that R2 be deleted. Since this is a "zero tolerance" standard any

Organization	Agree?	Question 11 Comment
Group		Transmission Owner will remove any discovered threats to prevent outages. While we agree that the implementation of an imminent threat procedure may be a valid concept, visualization of the Critical Clearance Zone and determining an approaching encroachment is a practice in application of theoretical conductor locations in real time.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Florida Power & Light	Disagree	FPL agrees that the Gallet equation is a better method to determine a Critical Clearance Zone. However, FPL does not agree with the application of the zone for several reasons outlined below. ? There are many environmental and engineering variables and assumptions included in the calculation of the Critical Clearance Zone. ? These assumptions are not clearly defined in the standard. ? Unless there is a significant intrusion into the Critical Clearance Zone, an engineer and surveyor would be necessary at all times to determine a violation. ? The success of this standard lies with a standard the field personnel can implement. When making actual trimming or removal decisions, the field personnel are not adequately skilled to do much more than make a rough guess at the Critical Clearance Zone. This standard must establish measurable and auditable parameters for field operations. ? In Requirement R2, determination of when to activate the Imminent Threat Procedure becomes unclear due to the difficulty in determining when the Critical Clearance Zone is encroached. ? As written, off ROW trees falling through the Critical Clearance Zone become a violation of Requirement R4. Unless an outage occurred, how would the utility determine that a violation occurred? In FAC 003-1 an outage of this nature is defined as Category 3 and is not a violation. Since fall-in tree interruptions have never been contributors to cascading events or blackouts they should not be a violation of a NERC standard. Consequently, as written, it is highly questionable whether this Standard is sufficiently specific and clear to be enforceable. The many questions and levels of confusion introduced with the application of the Critical Clearance Zone concept suggests that neither the industry nor NERC will ever know if compliance is met. Such a high level of ambiguity requires that the Critical Clearance Zone concept be revisited and most likely replaced with a measure that is workable for both the industry and NERC. To further this effort, FPL has outlined some alternative suggestions described in the answer to question 18.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		

Organization	Agree?	Question 11 Comment
Southern Company	Disagree	As written, R2 requires activation of the imminent threat process when the Critical Clearance Zone (CCZ) is "approached" by vegetation. The term "approach" is vague and open to interpretation. Since vegetation is dynamic in nature, it is constantly "approaching" any pre-defined zone. There could also be many examples given of encroachments into the theoretical CCZ that would neither threaten the transmission line conductor nor cause a reduction in the capacity of the transmission line. This concept would be better suited to be a “trigger point” that, if found, would be incentive for the Transmission Owner to take immediate action or ensure future action occurs on schedule. This action may be as urgent as implementation of the immediate threat procedure or as non-urgent as making sure that the upcoming maintenance on that line is scheduled appropriately. We are concerned this revision of FAC-003 continues to take a zero tolerance approach to compliance, which is contrary to the philosophy utilized in other NERC standards. A state of non-compliance should not exist simply because vegetation encroached within a pre-defined zone by a fractional inch, but only when an event, such as a sustained outage, occurs due to the Transmission Owner's failure to maintain adequate clearance between conductors and vegetation.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
E.ON U.S.	Disagree	E.ON U.S. suggests that R2 be deleted. Since this is a "zero tolerance" standard any Transmission Owner will remove any discovered threats to prevent outages. While we agree that the implementation of an imminent threat procedure may be a valid concept, visualization of the Critical Clearance Zone and determining an approaching encroachment is a practice in application of theoretical conductor locations in real time.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
FirstEnergy	Disagree	The CCZ is not equal to Clearance 2 in FAC-003-1. Per requirement R4, any encroachment into the CCZ is a violation of the standard even if an outage does not occur. This is too strict because it refers to a "0" tolerance even for encroachments that do not affect reliability. This can be an extremely costly standard to comply with that may or may not improve reliability. The CCZ distance is a difficult to determine from one moment to the next based upon the description and calculations outlined. The conditions on the right of way are dynamic and ever changing. It would be more proactive for the TO to focus on implementing the TVMP rather than expending time and money trying to determine if the CCZ has been violated. A better approach

Organization	Agree?	Question 11 Comment
		would be to establish a minimum clearance at all times rather than to monitor encroachment to a theoretical CCZ.
Response: Thank you for your comment. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Midwest ISO Stakeholders Standards Collaborators	Disagree	he CCZ is a good theoretical concept to aid industry in understanding the overall movement of conductors, but it is an impractical concept for field application. Due to the variability in the size of the CCZ as you move along a conductor, as well as changes from span to span or even line to line due to design parameters, loading or weather-related issues, the CCZ concept should not be tied to an imminent threat procedure. Vegetation approaching the CCZ does not constitute an imminent threat. It may be months to years before this vegetation ever gets to a proximity distance from the conductor to be within a "spark-over" distance as defined by the Gallet equations. Requirement R2 should support the purpose of this standard by requiring implementation of the Vegetation Imminent Threat Procedure when the Transmission Owner has visual, field knowledge that vegetation is encroaching upon a conductor within some specific distance that is a multiple of the Gallet distances referenced in Table I of FAC-003-2 (to be conservative we suggest two to three times the Gallet distances). Failure to implement the Vegetation Imminent Threat Procedure in such instances would be a violation of R2.As R2 is currently stated, a Transmission Owner cannot comply with R2 unless the imminent threat procedure is continuously being implemented, because vegetation that is growing is always approaching the CCZ. "Approaching the CCZ" cannot be the trigger for implementation of the Vegetation Imminent threat Procedure. Instead, the trigger should be an encroachment within some observed field distance. Requirement R2 could be reworded as follows: ?Each Transmission Owner shall implement its Vegetation Imminent Threat Procedure when the Transmission Owner has knowledge, obtained through normal operating practices or notification from others, that vegetation is encroaching upon a conductor within a distance that is twice the Gallet clearance distances referenced in Table I." Using a multiple of the Gallet distances provides a safety factor. Assessing a violation for failure to appropriately implement the Vegetation Imminent Threat Procedure or for a sustained vegetation-related outage incents the proper behavior.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4. The proposed standard revision specifies the MVCD as a starting point and TOs may apply multiples at its own discretion in order to achieve its TVMP objectives and adhere to applicable safety standards.		

Organization	Agree?	Question 11 Comment
SERC Compliance Staff	Disagree	SERC staff agrees that the implementation of an imminent threat procedure may be a valid concept; however visualization of the Critical Clearance Zone and determining an approaching encroachment will be difficult from a practical matter. There also needs to be definition of what is meant by "approaching" if this is used. While it may be a technically sound approach to designate the clearance zone to be tied to the conductor movement envelope as found in the NESC, this results in a banana-shaped zone that is difficult to substantiate in the field by entity and compliance personnel. It may be better, and more reasonable to define a constant zone around a conductor that would be the same throughout the span. The clearance zone should not include the limitation that the zone cannot extend outside the active right of way.
Response: Thank you for your comment. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
ITC HOLDINGS	Disagree	Just because vegetation is approaching the CCZ doesn't represent an imminent threat and should not be set to an imminent threat procedure. Implementation of R2 would require field personnel to determine the speculative position of the line during inspections to decide whether to engage the imminent threat procedures. While we agree that an imminent threat procedure should be implemented to address vegetation related imminent threats as soon as they are identified, we believe that an approach of the CCZ should not be used to generate implementation. The term "approached" does not identify a specific distance, so it's not clear to what extend vegetation would have to approach the CCZ to require implementation of the imminent threat process. ITC agrees that the implementation of an imminent threat procedure may be a valid concept, but visualization of the CCZ and determining approaching vegetation is a practice in hypothetical conductor locations in real time. This may be a good imaginary concept in understanding conductor movement but it's impractical for field applications.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Tennessee Valley Authority	Disagree	TVA recommends that R2 be removed from this standard. Since this is a "zero tolerance" standard there is a very significant incentive for the Transmission Owner to inspect and plan maintenance to prevent potential outages. The Gallet Equations should be kept within the white paper solely for the TO to reference for developing maintenance and inspection cycles.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has		

Organization	Agree?	Question 11 Comment
discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Exelon	Disagree	Comments: 1) In spite of the rigor associated with the Gallet equations, the definition of CCZ is imprecise as the Ratings to be used are not specified. In addition, Exelon is concerned that it will be difficult to determine the CCZ for each span under all possible operating conditions. Implementing an imminent threat procedure (R2) in combination with the CCZ may be unworkable under actual field conditions. 2) We are concerned that CCZ is only fully defined in the Technical Reference documentation and not in the standard itself. As stated in the NERC Standards Process Manual, Elements of a Reliability Standard, "Supporting documents to aid in the implementation of a standard may be referenced by the standard but are not part of the standard itself." There needs to be enough specificity as to the definition of CCZ in FAC-003-2 so that adequate documentation and evidence of compliance can be developed.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
American Electric Power (AEP)	Disagree	AEP agrees with the need for a TO to have an Imminent Threat Procedure and that the Transmission Operator should be immediately notified of imminent threats. However, AEP disagrees with the requirement that the Transmission Operator be notified merely because the CCZ has been approached. Vegetation approaching the CCZ does not necessarily constitute an imminent threat. It is possible that the CCZ is encroached by vegetation at the lowest point of the CCZ whereas the conductor may be at its highest point in the CCZ (potentially 20 or 30 feet away from the vegetation). This situation does not merit notification to the Transmission Operator. Please also refer to our comments regarding CCZ in AEP's responses to Questions 15 and 18.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		

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Platte River Power Authority	Disagree	Changing to the Gallet equation will not have a large impact on vegetation management operations, keeping Clearance 1 and 2 with tables developed using IEEE Standards for various voltages, line spans and altitudes is preferable. Actions should be taken to prevent an outage when vegetation encroaches Clearance 2.
Response: Thank you for your comment. The SDT chose to use Gallet equations over IEEE primarily because Gallet is more appropriate for determining the probability of flashover. The IEEE standard was developed for human safety purposes.		
Northern Indiana Public Service Company	Disagree	While I agree with the argument that the Gallet equatiion is a better technical or scientific method than IEEE 516 for determining realistic conductor to tree flashover distances, I do not agree that the new proposed clearance tables serve any useful purpose as a vegetation clearance standard from an operational perspective. The FAC-003-2 Technical Reference itself points to this fact when it states, "even if the exact size and shape of the C.C.Z. is known, it becomes nearly impossible in the field to correlate and accurately superimpose the C.C.Z. around the conductor." The Tech. Ref. goes on to say that "it is anticipated that many T.O.s will establish a work trigger well outside the C.C.Z." I agree wholeheartedly with that concept and believe that the Gallet clearance tables should be used by TO's to develop the more important "work trigger" or "action threshold" clearances. This revision is overly focused on C.C.A.'s that have no practical operational application while being silent to the more critical to reliability issue of "work trigger/action threshold" clearances. This needs to be addressed if we hope to be successful at achieving the goal of zero preventable tree related outages.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Tampa Electric Company	Disagree	This is a good start. The Critical Clearance Zone (CCZ) is a very real and practical concept; however, it is not transferable to field conditions. This could result in a "fill in the blank" standard relative to what the Critical Clearance Zone will be in terms of distance. As I read this, it will be a sliding scale from insulator to mid span and back for each designated line voltage. The max wind speed to be used and other assumptions behind the determination of this zone may be as involved a Gallet's formula. This will lead to complications during operational inspection and verification of these clearances.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission		

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Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Orange and Rockland Utilities Inc.	Disagree	While we agree that the imminent threat procedure should be implemented to address vegetation-related imminent threats as soon as they are identified, we believe that an "approach" of the CCZ should not be used to trigger implementation. The term "approached" does not identify a specific distance, so it is not clear to what extent vegetation would have to approach the CCZ in order to require implementation of the imminent threat process. This is left to the discretion of individual interpretation, is confusing to field personnel, and presents compliance and auditing problems. Imminent threats which are based on vegetation clearances should be identified based on specific clearances, not undefined approach distances. In practical field application the CCZ is an invisible area that changes shape and size along the length of the conductor. It is impossible to readily identify in the field without engineering calculations and precise measurements or the use of technology such as Aerial Laser Survey (ALS) using Light, Detection and Ranging (LIDAR) technology. Therefore under normal circumstances the location, size, and shape of the CCZ and vegetation encroachments of the CCZ can only be roughly estimated. Even with the use of ALS, which is relatively accurate, information is often not available for months after the survey flight. We believe that under normal circumstances imminent threats which are based on vegetation clearances should be identified in terms of specific distances from the conductor. While it is not possible for an inspector to readily identify a vegetation encroachment of the CCZ in the field, an inspector could more easily estimate a specified short distance between a conductor and vegetation in real time and initiate implementation of the imminent threat procedure based on that assessment. This assessment would be significantly more accurate than attempting to measure the distance between vegetation and the CCZ, which is not visible and constantly changes size and shape throughout the span. In cases where the Transmission Owner chooses to deploy ALS, the CCZ rather than the conductor could be used as the reference because in most cases the CCZ could be identified relative to approaching vegetation with a reliable degree of accuracy. Still a specific distance should be used to trigger implementation of the imminent threat procedure because of the issues previously raised with the use of the word "approached".
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
American Transmission Company	Disagree	ATC believes that the Critical Clearance Zone (CCZ) is a good theoretical concept to aid industry in understanding the overall movement of conductors, but it is an impractical concept for field application. Due to the variability in the size of the CCZ as you move along a conductor, as well as changes from span to span or

Organization	Agree?	Question 11 Comment
		even line to line due to design parameters, loading or weather-related issues, the CCZ concept should not be tied to an imminent threat procedure. Vegetation approaching the CCZ does not constitute an imminent threat. It may be months to years before this vegetation ever gets to a proximity distance from the conductor to be within a "spark-over" distance as defined by the Gallet equations. Requirement R2 should support the purpose of this standard by requiring implementation of the Vegetation Imminent Threat Procedure when the Transmission Owner has visual, field knowledge that vegetation is encroaching upon a conductor within some specific distance that is a multiple of the Gallet distances referenced in Table I of FAC-003-2 (to be conservative we suggest two to three times the Gallet distances). Failure to implement the Vegetation Imminent Threat Procedure in such instances would be a violation of R2.As R2 is currently written, a Transmission Owner cannot comply with R2 unless the imminent threat procedure is continuously being implemented or monitored, because vegetation that is growing is always approaching the CCZ. "Approaching the CCZ" cannot be the trigger for implementation of the Vegetation Imminent threat Procedure. Instead, the trigger should be an encroachment within some observed field distance. Requirement R2 could be rewritten as follows: ?Each Transmission Owner shall implement its Vegetation Imminent Threat Procedure when the Transmission Owner has knowledge, obtained through normal operating practices or notification from others, that vegetation is encroaching upon a conductor within a distance that is twice the Gallet clearance distances referenced in Table I." Using a multiple of the Gallet distances provides a safety factor. Assessing a violation for failure to appropriately implement the Vegetation Imminent Threat Procedure or for a sustained vegetation-related outage would promote the proper behavior.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4. The proposed standard revision specifies the MVCD as a starting point and TOs may apply multiples at its own discretion in order to achieve its TVMP objectives and adhere to applicable safety standards.		
Ameren	Disagree	The CCZ is a good theoretical concept to aid industry in understanding the overall movement of conductors, but it is an impractical concept for field application. Due to the variability in the size of the CCZ as you move along a conductor, as well as changes from span to span or even line to line due to design parameters, loading or weather-related issues, the CCZ concept should not be tied to an imminent threat procedure. Vegetation "approaching" the CCZ does not constitute an imminent threat. In fact, the moment after vegetation is cut, it begins again to "approach" this zone. It may be months to years before this vegetation ever gets to a proximity distance from the conductor to be within a "spark-over" distance as defined by the Gallet equations. Requirement R2 should support the purpose of this standard by requiring implementation of the Vegetation Imminent Threat Procedure when the Transmission Owner has visual, field knowledge that vegetation is encroaching upon a conductor within some specific distance. As R2 is currently stated, a

Organization	Agree?	Question 11 Comment
		Transmission Owner cannot comply with R2 unless the imminent threat procedure is continuously being implemented, because vegetation that is growing is always approaching the CCZ. "Approaching the CCZ" cannot be the trigger for implementation of the Vegetation Imminent threat Procedure. Instead, the trigger should be an encroachment within some observed field distance.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Nebraska Public Power District	Disagree	The CCZ is a good concept to explain the flight path of a conductor under all conditions but it would be impractical to use in the field. There are too many variables to consider and an encroachment does not constitute an immediate threat.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Manitoba Hydro	Disagree	The imminent threat process trigger should be well defined, and the vague "approaching" terminology needs to be changed. Imminent threat implies and that an elevated risk of contact exists. That is not the case if the vegetation is merely approaching the CCZ. The objective of the overall Vegetation Management program is to prevent an encroachment. The imminent threat procedure should be triggered by discovery of an encroachment into the CCZ. Even when an actual encroachment into the CCZ occurs - while the odds of an outage event have increased - the likelihood of a contact is still minimal, as other environmental factors still need to be in place (i.e. high temperature and/or high wind conditions).If this approach to an imminent threat process trigger, then the violation of this requirement implies a violation of R4, which prohibits the encroachment of the CCZ, and therefore either R2 or R4 could be removed, or they could be combined into one requirement.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. The Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Consumers Energy Company	Disagree	Absolutely disagree! The Gallet formula distances do not provide adequate protection of the system. The "Critical Clearance Zone" concept is not workable in the field. Every foot of every span would have a different

Organization	Agree?	Question 11 Comment
		CCZ that cannot be measured in the field without survey type equipment and knowledge of current line loadings. The clearance requirement needs to be uniform along the span for field crews to effectively achieve compliance. It appears that the drafting team hopes to minimize violations of vegetation violating FAC-003-1 Clearance 2 distances by decreasing the clearance distance between the conductor and vegetation using the Gallet formula. If NERC believes that FAC-003-1 Clearance 2 distances are too conservative, then the Gallet formula distance needs to be increased by some multiplier (2 or3) to achieve adequate safeguard for growing vegetation. Most trees in the United States in the size range that could exist beneath conductors achieve height growth of 3 feet or more annually. A tree in May may have adequate clearance per the proposed CCZ and in July violate that clearance causing an outage. Therefore, if the CCZ is to remain as is then the transmission owner/operator must have a defined imminent threat distance considerably greater than the CCZ and must be great enough that field personnel can safely remove the threat without de-energizing or de-rating the line.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4. The proposed standard revision specifies the MVCD as a starting point and TOs may apply multiples at its own discretion in order to achieve its TVMP objectives and adhere to applicable safety standards.		
Pacific Gas & Electric Co.	Disagree	PG&E agrees the Gallet equation is superior to IEEE 516 and the imminent threat procedure is a critical component of the standard but disagrees that initiation of the procedure be based on such ambiguous language as "approaching the CCZ". Approaching could be any and all vegetation that is live and growing and CCZ is a theoretical calculation not a real time event. As written, the standard would require the TO to initiate an emergency action when such action may not be warranted or necessary to prevent an outage. PG&E recommends using a clearly defined and measureable threshold to determine when the imminent threat procedure must be initiated. A reasonable threshold would be 3 times the Gallet clearance distances referred to in Table 1 or when vegetation is threatening to fall into or otherwise impact a line.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4. The proposed standard revision specifies the MVCD as a starting point and TOs may apply multiples at its own discretion in order to achieve its TVMP objectives.		

Organization	Agree?	Question 11 Comment
San Diego Gas & Electric	Disagree	We do not agree with replacing Clearance Zone 2 with the Critical Clearance Zone. We recommend the removal of R4 entirely from the standard.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Consolidated Edison Company of New York (CECONY)	Disagree	CECONY is in favor of using the Gallet equations as they provide a more realistic clearance distance for vegetation. We understand and agree that establishing a Critical Clearance Zone (CCZ) would provide the specific area that a conductor could possibly travel through during various field and weather conditions but we do not agree that this is the most practical approach. The main issue is that the wording '...the Critical Clearance Zone is approached by vegetation.....' is very vague and left open to wide interpretation which causes inconsistency and confusion throughout the industry. The CCZ changes throughout the length of each conductor in each span so a field inspector's job and an auditor's job become much more complicated when trying to confirm compliance when vegetation is present in the Actiove ROW. We feel that the time spent trying to measure and calculate the CCZ and then confirm compliance would be better spent initiating a response plan to safely remove the vegetation. The imminent threat procedure would only be implemented if vegetation encroaches beyond a specific distance from the conductor, not as it approaches the theoretical CCZ. Advanced technology would be required if a vegetation approach distance to the CCZ was to be calculated in the field. This is a very costly and time consuming requirement and does not efficiently meet the Standard's goal of ensuring reliability.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Duke Energy Corporation	Disagree	No. Duke believes that the CCZ is a good theoretical concept to aid industry in understanding the overall movement of conductors, but it is an impractical concept for field application. Due to the variability in the size of the CCZ as you move along a conductor, as well as changes from span to span or even line to line due to design parameters, loading or weather-related issues, the CCZ concept should not be tied to an imminent threat procedure. Vegetation approaching the CCZ does not constitute an imminent threat. It may be years before this vegetation ever gets to a proximity distance from the conductor to be within a "spark-over" distance

Organization	Agree?	Question 11 Comment
		as defined by the Gallet equations. Requirement R2 should support the purpose of this standard by requiring implementation of the Vegetation Imminent Threat Procedure when the Transmission Owner has visual, field knowledge that vegetation is encroaching upon a conductor within some specific distance that is a multiple of the Gallet distances referenced in Table I of FAC-003-2 (to be conservative we suggest two times the Gallet distances). Failure to implement the Vegetation Imminent Threat Procedure in such instances would be a violation of R2.As R2 is currently stated, a Transmission Owner cannot comply with R2 unless the imminent threat procedure is continuously being implemented, because vegetation that is growing is always approaching the CCZ. "Approaching the CCZ" cannot be the trigger for implementation of the Vegetation Imminent threat Procedure. Instead, the trigger should be an encroachment within an observed distance from vegetation to conductor that is twice the Gallet distances in Table I. Requirement R2 could be reworded as follows: ?Each Transmission Owner shall implement its Vegetation Imminent Threat Procedure when the Transmission Owner has knowledge, obtained through normal operating practices or notification from others, that vegetation is encroaching upon a conductor within a distance that is twice the Gallet clearance distances referenced in Table I." Using a multiple of the Gallet distances provides a safety factor. Assessing a violation for failure to appropriately implement the Vegetation Imminent Threat Procedure or for a sustained vegetation-related outage incents the proper behavior.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4. **The proposed standard revision specifies the MVCD as a starting point and TOs may apply multiples at its own discretion in order to achieve its TVMP objectives and adhere to applicable safety standards.**		
Entergy Services	Disagree	: 1. Entergy suggests that the requirement for activation of the vegetation imminent threat process should not be tied to the Critical Clearance Zone and that the each entity should define the activation of their vegetation imminent threat process. Tying the activation of the imminent threat process to the Critical Clearance Zone is limited in that this criterion does not address the possibilities of vegetation falling into the line or Critical Clearance Zone. 2. In the sentence "Critical Clearance Zone approached by vegetation" the use of "approached" is subjective and not specifically quantifiable. Effective, uniform activation of the imminent threat process will require objective measurement criteria. 3. The standard needs to include a clear statement to the effect that when the Transmission Operator is notified of a potential vegetation problem, obtained by normal operations and inspections, the entity will

Organization	Agree?	Question 11 Comment
		activate the Vegetation Imminent Threat Process. 4) This requirement, as stated, is redundant. The requirements for maintaining the Critical Clearance Zones and / or avoiding vegetation outages, and the associated Violation Risk Factors and Violation Severity Levels, already reinforce the desired behavior of the entity to identify and mitigate any potential issues before the possibility of vegetation causing an outage.
Response: Thank you for your comment. **1) The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4. These changes may address your concerns.** **2) Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The word, "approached" is not used in the revised standard.** **3) Requirement R1 Part 1.4 specifies the TVMP have an Imminent Threat procedure that includes notification of the responsible control center.** **4) The SDT believes that having to implement an Imminent Threat procedure is proactive behavior and is in support of prevention of outages.**		
Pepco Holdings, Inc	Disagree	R5, R6 and R7 make this requirement redundant and unnecessary - it should be deleted. It is largely unenforceable and does not make the standard clear, specific and regulatory enforceable. Further, PHI believes the concept of enforcing no encroachment into the Critical Clearance Zone is a flawed approach.
Response: Thank you for your comment. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4. **The SDT believes that having to implement an Imminent Threat procedure is proactive behavior and is in support of prevention of outages.**		
JEA	Disagree	The use of Gallet equations is not practical either for field use or for demonstrating compliance.
Response: Thank you for your comment. The SDT chose to use Gallet equations over IEEE primarily because Gallet is more appropriate for determining the probability of flashover and the SDT believes holds distinct advantages for use in vegetation management applications. IEEE 516 is developed for human safety purposes.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	We feel that changing to the Gallet equation will not have a large impact on its vegetation management operations, so we have no concerns. We agree with R2, but feel that this clause makes R4 redundant, as per

Organization	Agree?	Question 11 Comment
		our discussion under Comment # 15 below. We recommend the removal of R4 entirely from the standard.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
WECC	Agree	Yes but the wording is ambiguous. Vegetation under a transmission line is always "approaching" or growing towards the transmission line. Entities should define a specific distance greater than the Critical Clearance Zone when they are required to implement their Imminent Threat Procedures.
Response: Thank you for your comment. The proposed standard revision specifies a "Minimum Vegetation Clearance Distance" as a starting point and TOs may apply greater distances at their discretion in order to trigger implementation of the Imminent Threat procedure. The word, "approaching" is not used in the revised standard.		
Baltimore Gas & Electric Company	Agree	Again, each utility is responsible and accountable for it's actions. The Gallet clearances are a much better approximation of a true spark gap than the present requirement. Without a clearance one requirement, the closer tolerance produced by the Gallet equation will leave little room for error when a line is at or approaching it's max. engineered sag. When vegetation gets in the new CCZ (if adopted), it will be likely that an outage will be imminent. With the present clearance 1 and clearance 2 requirements, there is more of a buffer for encroaching vegetation.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4. The proposed standard revision specifies the MVCD as a starting point and TOs may apply multiples at its own discretion in order to achieve its TVMP objectives and adhere to applicable safety standards.		
CenterPoint Energy	Agree	We agree with replacing IEEE 516 standard distances with the Gallet equation standard distances. However, the term "Critical Clearance Zone" refers to the "limits of the Active Transmission Line Right-of-way" which has no specific definition as to its limits within the proposed revised Standard. (See comments to Q3 above.) R2 should be reworded to coordinate with R1.4. (See comments to Q4 above.)

<table>
<tr><th>Organization</th><th>Agree?</th><th>Question 11 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comments. Please see our responses to Questions 3 and 4 comments as well as the summary consideration for this question Based on stakeholder comments, the SDT made significant modifications to Requirement R2 and removed the concept of the CCZ.</td></tr>
<tr><td>Salt River Project</td><td>Agree</td><td>Although we agree that using the Gallet equation is more definitive than using IEEE 516, we still question from an engineering prespective as to how and why this method was chosen. It is stated in the Technical Reference paper that the Gallet Equation is a well known method of computing the required strike distance for proper insulation coordination. It is our understanding it's purpose is for designing towers, to define the "tower window" or opening inside of a tower under normal conditions. Because this is not a method designed specifically for vegetation management, was there any physical testing involved in choosing this approach, such as testing in both wet and dry conditions? We would recommend additional information to clarify this method to use for vegetation management. See additional comments in Comment #18 below. In addition, we feel this clause makes R4 redundant, as per our comments under Comment #15 below.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. The Gallet equations indeed are useful in tower design; however it is not exclusively for that purpose. The decision whether to use Gallet is not contingent upon testing and none were considered or conducted. No physical testing was utilized by the SDT; however, the Gallet Equation method and its explanation in the White Paper do have their basis in physical testing in both laboratory and field conditions. The Gallet Equation method is not solely applicable to tower structure design, but to any application requiring spark-over calculations. The SDT believes that the Gallet Equation method holds distinct advantages over the IEEE 516 method for use in vegetation management applications.</td></tr>
<tr><td>Southern California Edison Company</td><td>Agree</td><td>Q11: SCE agrees in part with proposed R2. The use of the Gallet equation and the replacement of the existing Clearance 2 requirement with the Critical Clearance Zone is acceptable. However, SCE strongly disagrees with establishing a separate requirement for implementing an imminent threat procedure should there be an encroachment of the Critical Clearance Zone because it forms the basis of an unnecessary zero-tolerance enforcement policy. Read in context with corresponding Measure 2, R2 appears to require Transmission Owners to prove that a Critical Clearance Zone encroachment did or did not occur and also prove that that an imminent threat procedure was or was not properly invoked. Although SCE agrees that CCZ encroachments should be addressed timely, we disagree with the notion and underlying assumption that a CCZ incursion will always lead to a flash-over or a vegetation-to-line contact. If the goal of FAC-003-2 is to prevent sustained outages (due to vegetation-to-line contacts) that could lead to Cascading, emphasizing “prevention” is understandable, however, enforcing prevention measures is an entirely different matter. Under the proposed requirements, a vegetation-to-line contact could conceivably represent two distinct violations of FAC-003-2. SCE believes this type of regulatory double jeopardy is patently unfair and forcing Transmission Owners to prove a CCZ encroachment did or did not occur is equally unfair and unenforceable. Because R1.4 adequately addresses the Transmission Owner’s responsibility regarding the implementation of an imminent threat procedure, SCE respectfully recommends that proposed R2 and corresponding M2 be removed from</td></tr>
</table>

Organization	Agree?	Question 11 Comment
		FAC-003-2.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Buckeye Power, Inc.	Agree	I agree with R2. I like the language changes, but decreasing the clearances will not improve reliability.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Great River Energy	Agree	GRE agrees and believes that the Gallet equation yields a less subjective measurement. GRE believes R2 should be modified to be more definitive. The imminent threat procedure should be implemented when vegetation “enters” the Critical Clearance Zone (CCZ). It is GRE's opinion that approaching the CCZ is subjective and as such very difficult to enforce.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	Attachment 1 is very conservative. I think that the clearance distances shown on the attachment should be expanded to create, in effect, a standard that reflects maximum line loading and maximum line sag. I would also like to see some flexibility built into the process so that the Transmission Owner and the USFS could negotiate some consideration for vegetation growth rates. The end result would generate a standard that would give the Transmission Owner the security of knowing that vegetation would not grow into the potential arcing zone for some reasonable amount of time - some kind of entry cycle.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT		

Organization	Agree?	Question 11 Comment
modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Measure M2 requires that the entity have evidence showing dates and activities accomplished to meet the R2 implementation requirement. The SDT notes that the proposed standard revision does not preclude the USFS and the TO from negotiating consideration for vegetation growth rates and in fact it is a good idea.		
City of Tallahassee	Agree	As long as we do not have to have evidence of using the calculation! We should be able to use Table I as provided.
Response: Thank you for your comment. Please see the summary response. Many commenters disagreed with this requirement and it has been substantially modified.		
Bonneville Power Administration	Agree	BPA agrees with R2, but refer to comments submitted regarding R4 (please see our response to Question #15) for related recommendations to R2.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
MRO NERC Standards Review Subcommittee	Agree	The MRO agrees and believes that the Gallet equation yields a less subjective measurement. The MRO believes R2 should be modified to be more definitive. The imminent threat procedure should be implemented when vegetation “enters” the critical clear zone. Fines and violations for approaching the zone is not measurable or enforceable. The MRO believes that "approached" is subjective and not enforceable and should be removed from the requirement.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Northern California Power Agency (NCPA)	Agree	
Santee Cooper	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	

Organization	Agree?	Question 11 Comment
Arizona Public Service Company	Agree	
Independent Electricity System Operator	Agree	
Northeast Utilities	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
NPCC	Agree	
WECC Reliability Coordination	Agree	
Kansas City Power & Light	Agree	
National Grid	Agree	
Long Island power Authority	Agree	
Central Maine Power Company		No comment

12. The Standard Drafting Team revised the spark-over (also referred to as "flashover") distance thresholds utilizing technically-equivalent Gallet equations in lieu of IEEE 516 minimum air insulation distance (MAID) calculations that were used in FAC-003-1. The rationale is that the minimum air insulation distances in IEEE 516 were safety clearances developed under laboratory conditions and thus there exists concern these distances may be too conservative to apply to lines operating in actual field conditions. Do you agree with this? If not, please explain.

Summary Consideration: The majority of responders (90%) agreed with this change. The minority view favored the continued use of IEEE 516 and four responders advocating removing the tables from the standard.

After reviewing the industry comments, the SDT continues to support the merits of using the Gallet equations and maintaining the tables in the standard. IEEE 516 values are safety clearances developed under laboratory conditions and thus these distances are inappropriate for vegetation spark-over clearances associated with lines operating in actual field conditions. In addition, IEEE Standards are subject to change which the SDT did not desire to have the Vegetation Reliability associated with an IEEE Standard that may change without proper consideration of the impact to the Vegetation Reliability Standard.

By using the Gallet distances, the SDT feels this is a technically sound, independent value that represents a true spark-over threshold distance. One must remember this is a minimum distance and the new requirement of 1.6 specifies the Transmission Owner develop a maintenance strategy to ensure these clearances are never violated.

Organization	Question 12	Question 12 Comment
SERC Compliance Staff	Disagree	While the actual sparkover distance may be more correctly calculated using the Gallet equations, SERC staff believes it is a less conservative approach to the goal of preventing vegetation related outages. If the concept of the CCZ will remain in the standard, we suggest that the tables based on the Gallet equations be removed from the standard and be kept in the technical white paper solely to assist in developing a common understanding of the theory behind the establishment of a CCZ. However, the CCZ will continue to be a very difficult, if not impossible, aspect of the standard to implement from the perspective of practical application and compliance enforcement.
Response: The SDT thanks you for your response. The SDT feels that the tables are an important component and should be part of the standard. The supporting documentation for the derivation of the tables resides in the technical reference document. The revised standard does not use the concept of the CCZ.		
Tennessee Valley Authority	Disagree	TVA agrees with this concept however as stated in Comment Question 11 response, this should be an element of the White Paper and should not be in the Standard Requirement.

Organization	Question 12	Question 12 Comment
Response: The SDT thanks you for your response. The SDT feels that the tables are an important component and should be part of the standard. The supporting documentation for the derivation of the tables resides in the technical reference document.		
Exelon	Disagree	Comments: By using the Gallet equations, the draft standard appears to support reducing the clearance requirements as compared to IEEE 516. Given what we believe would be the difficulties in applying the clearances as developed using the Gallet equation method, we question if dropping the IEEE 516 guidance could have the unintended consequence of reducing reliability.
Response: The SDT thanks you for your response. The reduction in the clearance distances is due to applying smaller transient over-voltage factors and not due to using the Gallet equations. The SDT feels that using the reduced over-voltage factors is a more realistic approach than using the maximum factors in version 1. The Gallet equations are only one of the factors in developing clearances. The utility must also consider sag, sway, growth, environmental conditions and other factors when developing an effective TVMP.		
Northern Indiana Public Service Company	Disagree	If T.O.'s are serious about public safety and potential electrical hazards or are required to comply with NESC/IEEE safety standards, then the greater, more conservative clearance distances must apply. On an complex issue where the aerial distances between live conductors and trees are dynamic and changing, I would prefer to be on the side of caution and on the side of safety. Given the history of cascading blackouts due to preventable tree contacts, there is a need to be conservative with the standards. I don't see it being in the public interest to argue that established minimum air insulation distances are inappropriately restrictive when applied to UVM.
Response: The SDT thanks you for your response. The Gallet equations are only one of the factors in developing clearances. The utility must also consider sag, sway, growth, environmental conditions and other factors when developing an effective TVMP.		
Consumers Energy Company	Disagree	The Gallet distances severely lessen the reliability of the transmission system since there is not a define imminent threat distance and the Clearance 1 distances have been removed from this draft. The IEEE 516 distances provided a safety margin to allow for vegetation to grow and not be a reliability risk. A transmission owner/operator of a moderate size could not effectively inspect often enough during the growing season to protect lines from outages when trees are permitted to approach the Gallet formula distance and not be a violation. Such close distances would permit utility management to severely cut vegetation management budgets and allow trees to grow for 1-2 years beyond their scheduled maintenance cycle and not be in violation. But, 2-3 years after the budget cut, the field operation would be faced with an insurmountable amount of trees needing addressed and limited timeframes to complete the work. This is basically how the blackout occurred and this standard decreases the requirements to allow this to happen again.
Response: The SDT thanks you for your response. The Gallet equations are only one of the factors in developing clearances. The utility must also		

Organization	Question 12	Question 12 Comment
consider sag, sway, growth, environmental conditions and other factors when developing an effective TVMP.		
Baltimore Gas & Electric Company	Disagree	As noted in 11 above, the Gallet equation would appear to be a much closer approximation of the actual spark gap/flashover distance. It seems as though the new std. is making the protective zone around the conductors smaller by replacing the Clearance 2 requirement with the CCZ, while at the same time eliminating any other type of consideration for how much clearance needs to be achieved while trimming. All things being equal, if the only demarcation for when vegetation is a threat to the lines is the clearance 2 or CCZ areas, it would make sense to have this area be larger rather than smaller. Accordingly, I would recommend that the Clearance 2 value continue to be used instead of the Gallet equation-created CCZ.
Response: The SDT thanks you for your response. The Gallet equations are only one of the factors in developing clearances. The utility must also consider sag, sway, growth, environmental conditions and other factors when developing an effective TVMP. Note that the revised standard does not use the concept of the CCZ.		
SERC Vegetation Management Subcommittee (VMS)	Agree	Developing minimum sparkover distances in this standard is a superior approach for the stated reason in question 12. In addition, referring to tables and values in another standard is problematic if the referenced standard is revised and the tables are re-numbered or deleted altogether. We suggest that the tables based on the Gallet equations be removed from the standard and be kept in the technical white paper solely to assist in developing a common understanding of the threshold for taking actions.
Response: The SDT thanks you for your response. The SDT feels that the tables are an important component and should be part of the standard. The supporting documentation for the derivation of the tables resides in the technical reference document.		
SERC OC Standards Review Group	Agree	Developing minimum sparkover distances in this standard is a superior approach for the stated reason in question 12. In addition, referring to tables and values in another standard is problematic if the referenced standard is revised and the tables are re- numbered or deleted altogether. The SERC OOCSRG suggests that the tables based on the Gallet equations be removed from the standard and be kept in the technical white paper solely to assist in developing a common understanding of the threshold for taking actions.
Response: The SDT thanks you for your response. The SDT feels that the tables are an important component and should be part of the standard. The supporting documentation for the derivation of the tables resides in the technical reference document.		
Western Utility Arborists	Agree	The Western Utilities feel that changing this will not have a large impact on its vegetation management operations, so we have no concerns.
Response: The SDT thanks you for your response.		

Organization	Question 12	Question 12 Comment
American Electric Power (AEP)	Agree	AEP agrees that the Gallet Equation method is a reasonable and appropriate replacement for the IEEE 516 method.
Response: The SDT thanks you for your comments.		
Platte River Power Authority	Agree	Changing this will not have a large impact on vegetation management operations, so we have no concerns.
Response: the SDT thanks you for your comments.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	See comment for Question 11.
Response: The SDT thanks you for your response. The Gallet equations are only one of the factors in developing clearances. The utility must also consider sag, sway, growth, environmental conditions and other factors when developing an effective TVMP.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	We feel that changing this will not have a large impact on its vegetation management operations, so we have no concerns.
Response: The SDT thanks you for your comments.		
Salt River Project	Agree	As commented in Comment #11 above, although we agree that using the Gallet equation is more definitive than using IEEE 516, we still question from an engineering prespective as to how and why this method was chosen. It is stated in the Technical Reference paper that the Gallet Equation is a well known method of computing the required strike distance for proper insulation coordination. It is our understanding it's purpose is for designing towers, to define the "tower window" or opening inside of a tower under normal conditions. Because this is not a method design specifically for vegetation management, was there any physical testing involved in choosing this approach, such as testing in both wet and dry conditions? We would recommend additional information to clarify this method to use for vegetation management. See additional comments in Comment #18 below.
Response: The SDT thanks you for your response. The SDT searched for a method other than the laboratory condition based IEEE 516 method to determine minimum spark-over distances. The Gallet equations were derived for both wet and dry conditions and have been successfully used in many design applications. The SDT feels that using these equations to derive these minimum distances is a conservative approach. We also expect that the TO must also consider sag, sway, growth, environmental conditions and other factors when developing clearances for an effective TVMP.		

Organization	Question 12	Question 12 Comment
Buckeye Power, Inc.	Agree	I understand the reasoning for the change, but I do not see how decreasing clearances will increase reliability.
Response: The SDT thanks you for your response. The Gallet equations are only one of the factors in developing clearances. The utility must also consider sag, sway, growth, environmental conditions and other factors when developing an effective TVMP.		
British Columbia Transmission Corp	Agree	BCTC feels that changing this will not have a large impact on its vegetation management operations, so we have no concerns.
Response: The SDT thanks you for your response.		
Associated Electric Cooperative Inc.	Agree	
NPCC	Agree	
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
Progress Energy Florida	Agree	
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Progress Energy Carolinas	Agree	
Southern California Edison Company	Agree	Q12: No comments.

Organization	Question 12	Question 12 Comment
Florida Power & Light	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
Bonneville Power Administration	Agree	
FirstEnergy	Agree	
MRO NERC Standards Review Subcommittee	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	
ITC HOLDINGS	Agree	
Central Maine Power Company	Agree	
City of Tallahassee	Agree	
Northern California Power Agency (NCPA)	Agree	
Tampa Electric Company	Agree	
Orange and Rockland Utilities Inc.	Agree	
Ameren	Agree	

Organization	Question 12	Question 12 Comment
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Manitoba Hydro	Agree	
National Grid	Agree	
Pacific Gas & Electric Co.	Agree	
San Diego Gas & Electric	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Arizona Public Service Company	Agree	
Duke Energy Corporation	Agree	
CenterPoint Energy	Agree	
Entergy Services	Agree	
Pepco Holdings, Inc	Agree	
JEA	Agree	
Independent Electricity System	Agree	

Organization	Question 12	Question 12 Comment
Operator		
Northeast Utilities	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
Great River Energy	Agree	

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13. The Standard Drafting Team applied a transient overvoltage factor (T) of 1.4 and 2.0 for ac voltage classes of 345kV and above and sub-345kV facilities, respectively. Version 1, using the IEEE 516 method, assumes a maximum transient overvoltage value. The Standard Drafting Team asserts that in this application of steady-state flashovers and due to the design attributes of higher voltage systems, a lower T factor is applicable. Do you agree with this? If not, please explain.

Summary Consideration: The majority of responders (93%) agreed with this change. Two responders commented that they use a more conservative transient over-voltage factor in their design.

The SDT chose its transient over-voltage factors ("T") as being the most appropriate values for the industry as a whole. The majority of industry stakeholder comments supported this decision. It is permissible to use more conservative values if the Transmission Owner so desires.

Organization	Agree ?	Question 13 Comment
BCTC		BCTC feels that changing this will not have a large impact on its vegetation management operations, so we have no concerns.
Response: The SDT thanks you for your response.		
Tennessee Valley Authority	Disagree	TVA agrees with this concept however as stated in Comment Question 11 response, this should be an element of the White Paper and should not be in the Standard Requirement.
Response: The SDT thanks you and refers you to the response to Question 11.		
Exelon	Disagree	We disagree with the T factors that are proposed as our design is more conservative.
Response: The SDT thanks you and also acknowledges that various utilities may employ various T factors in their line designs. However, the SDT chose this value as the most appropriate value for the industry as a whole. Individual Transmission Owners are free to establish larger zones around the conductor than that established by the new MVCD. MVCD as currently drafted establishes a minimum value, not the only value.		
Manitoba Hydro	Disagree	Manitoba Hydro has historically designed the ROW clearance requirements based on an operating limitation of not switching during extreme wind conditions, therefore, beyond a wind pressure of 230 Pa, our design does not account for switching surge over voltages. We do however, agree with the use of overvoltage factors

Organization	Agree ?	Question 13 Comment
		as described above for wind conditions of less than 230 Pa.
Response: The SDT thanks you for your comments. Industry as a whole. Individual Transmisssion Owners are free to establish larger zones around the conductor than that established by the new MVCD. MVCD as currently drafted establishes a minimum value, not the only value.		
National Grid	Disagree	No opinion.
Response: The SDT thanks you for your comments. The SDT believes that it has chosen an approach that is the most appropriate method for the industry as a whole.		
SERC Vegetation Management Subcommittee (VMS)	Agree	See comments in #12 above.
Response: The SDT thanks you for your comments. See response to #12.		
SERC OC Standards Review Group	Agree	See comments in #12 above.
Response: The SDT thanks you for your comments. See response to #12.		
Salt River Project	Agree	As commented in Comments #11 & #12 above, although we agree that using the Gallet equation is more definitive than using IEEE 516, we still question from an engineering prespective as to how and why this method was chosen. It is stated in the Technical Reference paper that the Gallet Equation is a well known method of computing the required strike distance for proper insulation coordination. It is our understanding it's purpose is for designing towers, to define the "tower window" or opening inside of a tower under normal conditions. Because this is not a method design specifically for vegetation management, was there any physical testing involved in choosing this approach, such as testing in both wet and dry conditions? We would recommend additional information to clarify this method to use for vegetation management. See additional comments in Comment #18 below.
Response: The SDT thanks you for your comments. No physical testing was utilized by the SDT; however, the Gallet Equation method and its explanation in the White Paper do have their basis in physical testing in both laboratory and field conditions. The Gallet Equation method is not solely applicable to tower structure design, but to any application requiring spark-over calculations. The SDT believes that the Gallet Equation method holds distinct advantages over the IEEE 516 method for use in vegetation management applications.		
Western Utility Arborists	Agree	The Western Utilities feel that changing this will not have a large impact on its vegetation management

Organization	Agree ?	Question 13 Comment
		operations, so we have no concerns.
Response: The SDT thanks you for your comments.		
American Electric Power (AEP)	Agree	AEP agrees that the choice of transient overvoltage factors is sufficiently sound.
Response: The SDT thanks you for your comments.		
Platte River Power Authority	Agree	Changing this will not have a large impact on vegetation management operations, we have not concerns.
Response: The SDT thanks you for your comments.		
City of Tallahassee	Agree	As long as we do not have to have evidence of using the calculation! We should be able to use Table I as provided.
Response: The SDT thanks you for your comments.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	We feel that changing this will not have a large impact on its vegetation management operations, so we have no concerns.
Response: The SDT thanks you for your comments.		
Southern California Edison Company	Agree	Q13: No comments.
Associated Electric Cooperative Inc.	Agree	
NPCC	Agree	
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
Progress Energy Florida	Agree	

Organization	Agree ?	Question 13 Comment
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Progress Energy Carolinas	Agree	
Florida Power & Light	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
Bonneville Power Administration	Agree	
FirstEnergy	Agree	
MRO NERC Standards Review Subcommittee	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	
Central Maine Power Company	Agree	
Northern California Power Agency (NCPA)	Agree	

Organization	Agree ?	Question 13 Comment
Tampa Electric Company	Agree	
Orange and Rockland Utilities Inc.	Agree	
Ameren	Agree	
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Consumers Energy Company	Agree	
Pacific Gas & Electric Co.	Agree	
San Diego Gas & Electric	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Arizona Public Service Company	Agree	
Duke Energy Corporation	Agree	
CenterPoint Energy	Agree	
Entergy Services	Agree	
Pepco Holdings, Inc	Agree	

Organization	Agree ?	Question 13 Comment
JEA	Agree	
Independent Electricity System Operator	Agree	
Northeast Utilities	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
Buckeye Power, Inc.	Agree	
Great River Energy	Agree	
Baltimore Gas & Electric Company		I have no expertise to respond to this question.
Northern Indiana Public Service Company		No comment.
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM		Don't know!

14. R3 has been added to clarify that conduction of inspections is a separate requirement from specifying the frequency that inspections will occur. Do you agree with R3? If not please explain.

Summary Consideration: The majority of commenters (85%) were in favor of the standard as written. There were minority comments that wanted a reformatting of the standard to put documentation and implementation side by side. Following the directives in FERC order 693 and the SAR to bring the standard in line with the Sanction Guidelines, the SDT created a separate requirement, R3 that explicitly requires inspections be conducted. This is to differentiate R3 from Requirement 1, Part 1.2. Addressing inspections separately allows for appropriate assignment of VRFs and VSLs.

Organization	Agree?	Question 14 Comment
BCTC		BCTC understands that it's possible to have a schedule and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the schedule is kept together with the requirement to implement it.
Response: The SDT thanks you for your comment. The SDT considered other sequence options and suggest a new sequence for the industry to comment upon. See related question in the second Comment Form.		
Western Utility Arborists		The Western Utilities understands that it's possible to have a schedule and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the schedule is kept together with the requirement to implement it.
Response: The SDT thanks you for your comment. The SDT considered other sequence options and suggest a new sequence for the industry to comment upon. See related question in the second Comment Form.		
Progress Energy Florida	Disagree	The standard has established a threshold of compliance. For consistency, compliance should be measured at the threshold not a Registered Entities program requirement.
Response: The SDT thanks you for your comments. R3 clarifies that the inspections in the TVMP are to be conducted. The TVMP defines a Transmission Operator's standards. The general application of NERC standards is that a Transmission Operator is to adhere to the standards it establishes.		
Progress Energy Carolinas	Disagree	The standard has established a threshold of compliance. For consistency, compliance should be measured at the threshold not a Registered Entities program requirement.
Response: The SDT thanks you for your comments. R3 clarifies that the inspections in the TVMP are to be conducted. The TVMP defines a Transmission		

Organization	Agree?	Question 14 Comment
Operator's standards. The general application of NERC standards is that a Transmission Operator is to adhere to the standards it establishes.		
Southern California Edison Company	Disagree	Q14: SCE does not agree with the inclusion of proposed R3 and believes it should be replaced with a modified version of proposed R8.SCE respectfully suggests that proposed R8 be revised to read: "Each Transmission Owner shall implement and follow its Vegetation Management Program to the extent allowed by existing easement and/or legal rights."
Response: The SDT thanks you for your comments. Inspections are a key element of an effective TVMP. The SDT therefore decided to explicitly require that inspections be conducted in accordance with the Transmission Owners' requirements. In addition, addressing inspections separately allows for appropriate assignment of VRFs and VSLs.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Disagree	We understand that it is possible to have a schedule and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the schedule is kept together with the requirement to implement it.
Response: The SDT thanks you for your comment. The SDT decided to explicitly require that inspections be conducted in accordance with the Transmission Owners' requirements. Addressing inspections separately allows for appropriate assignment of VRFs and VSLs.		
San Diego Gas & Electric	Disagree	The information should not be separated. It will be much easier to follow if the requirement to have the schedule is kept together with the requirement to implement it.
Response: The SDT thanks you for your comment. The SDT decided to explicitly require that inspections be conducted in accordance with the Transmission Owners' requirements. Addressing inspections separately allows for appropriate assignment of VRFs and VSLs.		
Edison Electric Institute	Disagree	Consistent with previous comments, NERC should respond to FERC Order No. 693 Paragraph 721 regarding compliance audit procedures to identify appropriate inspection cycles.
Response: The SDT thanks you for your comment. The SDT decided to explicitly require that inspections be conducted in accordance with the Transmission Owners' requirements. Your comment has been forwarded to NERC staff. The Reliability Standard Audit Worksheet is where the FERC Order is addressed with respect to compliance audit procedures to identify appropriate inspection cycles.		
Baltimore Gas & Electric Company	Disagree	If frequency of inspections are required to be specified, it is implied that the inspections will follow. I suggest that R3 be eliminated and R1.2 be reworded to say: "Vegetation inspections shall occur at least once per year, or more frequently as dictated by local and environmental factors. Specify the frequency of when vegetation inspections will occur."

Organization	Agree?	Question 14 Comment
Response: The SDT thanks you for your comment. The SDT decided to explicitly require that inspections be conducted in accordance with the Transmission Owners' requirements. Addressing inspections separately allows for appropriate assignment of VRFs and VSLs. The STD believes that the phrase "Specify a vegetation inspection frequency…" adequately requires the Transmission Operator to ". . . .specify the frequency…"		
JEA	Disagree	See comment from #3.
Response: The SDT thanks you for your comment. This was addressed in the response to question 3.		
Salt River Project	Disagree	The document would be easier to follow if the two elements would be kept together in the same requirement (similar to comments stated in Comments #4 & #6 above). It makes the standard longer than necessary and creates redundancy.
Response: The SDT thanks you for your comment. The SDT decided to explicitly require that inspections be conducted in accordance with the Transmission Owners' requirements. Addressing inspections separately allows for appropriate assignment of VRF and VSLs.		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 14
Response: The SDT thanks you for your comment.		
American Electric Power (AEP)	Agree	AEP agrees with this change.
Response: The SDT thanks you for your comment.		
Platte River Power Authority	Agree	The separation allows lower sanctions and penalties to be assessed for a weak schedule and higher sanctions and penalties to be assessed for not implementing schedules. However, we feel that the standard itself would be easier to follow if it was re-organized so that the requirement to have the schedule is kept together with the requirement to implement it.
Response: The SDT thanks you for your comment. The SDT decided to explicitly require that inspections be conducted in accordance with the Transmission Owners' requirements. Addressing inspections separately allows for appropriate assignment of VRFs and VSLs.		
Arizona Public Service Company	Agree	APS understands that it's possible to have a schedule and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the schedule is kept together with the requirement to implement it.

Organization	Agree?	Question 14 Comment
Response: The SDT thanks you for your comment. The SDT decided to explicitly require that inspections be conducted in accordance with the Transmission Owners' requirements. Addressing inspections separately allows for appropriate assignment of VRFs and VSLs.		
Associated Electric Cooperative Inc.	Agree	
NPCC	Agree	
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
SERC Vegetation Management Subcommittee (VMS)	Agree	
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
SERC OC Standards Review Group	Agree	
Florida Power & Light	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	

Organization	Agree?	Question 14 Comment
Bonneville Power Administration	Agree	
FirstEnergy	Agree	
MRO NERC Standards Review Subcommittee	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	
Exelon	Agree	
Central Maine Power Company	Agree	
City of Tallahassee	Agree	
Northern California Power Agency (NCPA)	Agree	
Northern Indiana Public Service Company	Agree	
Tampa Electric Company	Agree	
Orange and Rockland Utilities Inc.	Agree	
American Transmission	Agree	

Organization	Agree?	Question 14 Comment
Company		
Ameren	Agree	
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	
Manitoba Hydro	Agree	
Consumers Energy Company	Agree	
National Grid	Agree	
Pacific Gas & Electric Co.	Agree	
Hydro One Networks Inc.	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Duke Energy Corporation	Agree	
CenterPoint Energy	Agree	
Entergy Services	Agree	
Pepco Holdings, Inc	Agree	

Organization	Agree?	Question 14 Comment
Independent Electricity System Operator	Agree	
Northeast Utilities	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
Buckeye Power, Inc.	Agree	
Great River Energy	Agree	

15. Several alternatives to R4 were considered by the drafting team. The drafting team explored these significantly different alternatives at length. They are outlined below to provide background to industry during this comment period. (Please refer to pages 22-32 in the Technical Reference Document on the Critical Clearance Zone for further background for this question.) Do you agree that R4 is written in the most effective way to achieve the purpose of the standard? If not, what do you propose as an alternative to R4 that would ensure a level of reliability equal to or better than FAC-003-1?

As written, R4, a new requirement, stipulates that the Transmission Owner is in violation if an encroachment of the Critical Clearance Zone occurs at any time. If vegetation enters the Critical Clearance Zone, a violation will have occurred, regardless of the actual proximity of the vegetation to the conductor at the time. Evidence will be required to prove that no encroachments of the Critical Clearance Zone have occurred anywhere at any time during the annual compliance period. This will require the time and effort to postpone vegetation maintenance to perform field investigations and document all possible encroachments.

One alternative to R4 required immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the Critical Clearance Zone, thereby proactively preventing an outage. A violation would have occurred only if the imminent threat process was not successfully implemented.

Another alternative was a tiered approach. This tiered approach involved a "per thousand mile" metric to determine when a violation had occurred and the severity of the violation. This metric was an attempt to equitably account for varying exposures that exist due to widely ranging system sizes.

Summary Consideration: Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The Critical Clearance Zone has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.

Ninety-four percent of the commenters disagreed with the proposed alternatives. The SDT classified the comments into 44 different concepts with many commenters weighing in on several concepts. For 37 commenters the dominant concept was "Measure M4 requires proof of no encroachments, i.e., "prove a negative", compliance certification is difficult." Below is a redlined version of R4. reflecting the changes that were made by the SDT.

R4. Each Transmission Owner shall prevent encroachment of vegetation into the Minimum Vegetation Clearance Distances ("MVCD") listed in Attachment 1 for its applicable lines as observed in real-time operating between no-load and their Rating with the following exceptions: *[Violation Risk Factor VRF= Medium][Time Horizon – Real Time]*

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- Encroachment into the Minimum Vegetation Clearance Distances listed in Attachment 1 resulting from natural disasters.[2]
- Encroachment into the Minimum Vegetation Clearance Distances listed in Attachment 1 resulting from human or animal activity.[3]
- Brief encroachment into the Minimum Vegetation Clearance Distances listed in Attachment 1 resulting from falling vegetation.

The SDT further weighed the NERC interpretation of the vegetation management standard during FERC's consideration of proposed FAC-003-1: A vegetation-related transmission line outage as a result of vegetation that has grown into the pre-defined clearance zone is a violation of the standard. The Commission adopted that interpretation when it approved NERC's proposed reliability standards. It stated, "FAC-003-1 requires sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions."4

In reviewing the comments and the FERC opinion the SDT considered 4 options:

- Re-word R4 and keep R4 the way it was originally intended (violation would only be if you had the outage) (Alternative B of Question 15**) {implies that R5, R6, & R7 are retained}
- Remove R2 and R4 from the standard. Keep the Critical Clearance Zone concept in the white paper.
- Remove R4 from the standard and revise R2 to have a "trigger distance" for implementation of the imminent threat process. Keep the Critical Clearance Zone concept in the white paper. Team would need to consider the true definition of an imminent threat.
- Return to the Clearance 2 concept. But define (somehow) that this is a "real time" violation only. Distance could be defined as the Gallet distance or a multiple of the Gallet distance.

The SDT made the following changes in line with bullet 4.

R4. Each Transmission Owner shall prevent encroachment of vegetation into the Minimum Vegetation Clearance Distances (MVCD) listed in FAC-003-2 - Attachment 1 for its applicable lines as observed in real-time operating between no-load and their Rating, with the following exceptions:

- Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from natural disasters.[4]

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[2] Examples include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods.

[3] Examples include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation.

- Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from human or animal activity.[5]
- Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from falling vegetation.

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Organization	Agree?	Question 15 Comment
PJM Interconnection		The current version of this standard, FAC-003-1, kept the subject of vegetation outside of the Rights of Way in the standard. Why are outside of Rights of Way vegetation issues not mentioned in FAC-003-2, or some responsibility for looking for outside of Rights of Way imminent threats or issues requiring corrective action plans not addressed?
Response: The SDT thanks you for your comments. Trees outside of the right of way should be identified and removed as necessary as they are identified as a threat to the reliability of the line. This function should be part of a vegetation management program as a follow up to the inspection process. Any vegetation that could pose a threat to the reliability to the line found during the inspection process should be remedied. The purpose statement for FAC-003-2 states that the standard is intended to improve the reliability of the electric transmission system by preventing vegetation related outages that could lead to Cascading.		
BCTC		The new requirement in R4 stipulates that the Transmission Owner is in violation if an encroachment of the CCZ occurs at any time. However, the CCZ changes with each foot of the transmission line from the insulator to the mid-span, depending on loading, actual operating temperature, wind loading, ice loading, maximum design rating, maximum operating load, and so on. Further, Measure M4 requires that the Transmission Owner has evidence demonstrating there were no vegetation encroachments into the CCZ. These requirements may result in having to LIDAR the lines annually, to prove that trees have not encroached upon the CCZ. This would be an extremely onerous and expensive requirement for utilities. BCTC strongly supports the alternative to R4 as recommended in the Comment Form (#15), which is to require immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the CCZ, thereby proactively preventing an outage. This means a violation would occur only if the imminent threat process is not successfully implemented. This alternative is essentially the same as R2. Therefore, BCTC recommends removing R4 from the standard entirely.

[4] Examples include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods.

[5] Examples include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation.

Organization	Agree?	Question 15 Comment
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Associated Electric Cooperative Inc.	Disagree	Associated Electric Cooperative Inc believes this requirement, as written, is unreasonable since it would prevent (or at least result in noncompliance) the intrusion within the Critical Clearance Zone (CCZ) of anything or anyone, including qualified line workers and their tools. It is suggested the words “of vegetation” be added between encroachment and within. The requirement would then read, “Each Transmission Owner shall prevent encroachment of vegetation within the Critical Clearance Zone of its applicable lines with the following exceptions:” The complexity of determining an encroachment into the Critical Clearance Zone is overly burdensome, requiring engineering calculations and possibly the need for precision measurements. The Transmission Owner (TO) cannot demonstrate compliance with the Requirement and its companion Measure, M4, since a negative cannot be proven. Therefore, since the TO must demonstrate compliance (guilty until proven innocent), it is automatically in violation of the Standard.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time. The SDT, for clarity, did add the phrase “of Vegetation” as requested.		
NPCC	Disagree	The purpose of the standard is "To improve the reliability of the Bulk Electric System by preventing vegetation related outages that could lead to Cascading". We believe that R4 is not the most effective way to achieve this purpose because it does not provide incentive for Transmission Owners to take advantage of modern technology, such as aerial laser survey (ALS) using Light Detection and Ranging technology (LIDAR), that is capable of accurately identifying vegetation which is approaching the CCZ or has encroached into it. In fact R4 provides an incentive not to utilize this technology because Transmission Owners who identify encroachments would be in violation of R4 for each identified encroachment. On the other hand, Transmission Owners who choose to be less proactive often would not identify such encroachments because the CCZ and encroachments of it are generally not easy to determine without taking precise measurements. Unless the line is heavily loaded or the vegetation is significantly overgrown, encroachments of the CCZ would not be readily noticed. In most cases these Transmission Owners would simply remove or cut back incompatible vegetation without taking measurements. The threat to the line would have been eliminated with no encroachment having been identified.R4 presents a dilemma for Transmission Owners that are considering making the significant investment in ALS technology. While the technology would allow them to identify any potential grow-in or fall-in conditions, it would also expose them to the risk of identifying violations of R4, that would otherwise not have been identified. Violation Risk Factors

Organization	Agree?	Question 15 Comment
		(VRFs), Violation Severity Levels (VSLs), and Time Horizons are not included in this Draft, but after making a significant investment in ALS, Transmission Owners could be faced with significant additional cost in terms of NERC penalties. In addition, even if the penalties were relatively low they would be exposing themselves to violations that less proactive Transmission Owners would not be exposed to. In our view R4 as written would, in some cases, have the opposite effect of what is intended because the business case for using ALS is more difficult to make. This will result in less use of ALS and other emerging technology that is likely to be developed. This would result in fewer problems being identified, a small percentage of which will not be discovered until they result in a line trip. Still we believe that the concept of the CCZ is a good one and recommend that R4 be changed so that Transmission Owners are provided with an incentive to invest in the best technology available in order to ensure the highest level of reliability. The opportunity exists to develop the standard in a manner that encourages the industry to take advantage of new technology and manage vegetation in a very proactive way. We recommend that R4 be changed as follows: Modify R4 to require Transmission Owners to immediately implement the imminent threat process defined in R1.4 when they identify instances where the CCZ is approached or encroached upon. Failure to do so would be a violation of R4. Eliminate encroachment of the CCZ as a violation of R4. This would eliminate R2 and incorporate implementation of the imminent threat process into R4.Require Transmission Owners to report to the Regional Entity on a quarterly basis any instances where the imminent threat process was implemented due to an encroachment of the CCZ. This would add a reporting requirement for Transmission Operators. Require Transmission Owners to report to the Regional Entity on a quarterly basis any instances where either a momentary or sustained outage was caused by grow-ins, Active Transmission Line Right of Way blow-ins, or Active Transmission Line Right-of-Way fall-ins. This would add three additional reporting requirements for Transmission Operators. Require Regional Entities to perform additional audits of Transmission Owners that exceed metrics for violations of the CCZ . The metrics would be established in this Standard based upon 100 circuit miles of applicable lines. This would add an additional requirement for Regional Entities. This concept would result in a more rigorous standard than FAC-003-01 because of the additional reporting and auditing requirements. It would drive proactive behavior throughout the industry and provide a significant incentive for Transmisison Owners to invest in new technology such as ALS that is capable of accurately identifying vegetation that has approached or encroached upon the CCZ. We believe that this change would result in the identification of more incipient vegetation-related problems and fewer vegetation-related outages as soon as it was implemented and would best support the purpose of the Standard.

Response: The SDT thanks you for your comments. The SDT concurs that the use of ALS – LiDar technology, while expensive, could enhance reliability. However several team members have made the investment and concur that the technology including interpertation software are not sufficiently mature to be put in a standard. In addition in some cases it would not be cost justifiable over traditional methods of inspection. During the course of our deliberations the team questioned both FERC and RE staff's response to a utility finding encrochments with ALS technology and concluded the auditor would not forgive encrochment even though the Transmission Owner went to extraordinary means to find the encrochment.

Initially the team approached the FERC staff in a meeting in Washington with a proposal that an encrochment not be a violation if the Transmission Owner implemented the imminent threat procedure successfully before an interruption occurred. The concept was rebuffed by the FERC Staff as a step

Organization	Agree?	Question 15 Comment
backwards from version 1. **The SDT very carefully and thoroughly examined the merits, disadvantages, ease and difficulties of assessing momentary outages as a violation. The result of that effort led to the more precise and field observable aspects of R4. It should be noted that by their very nature the exact causes of "momentary outages" are very challenging to determine and will vary widely from utility to utility. The SDT did not find that such variability was appropriate for a reliability standard, and chose to address this issue with the language in R4.** **Due to the industry impact that arises from zero tolerance for vegetation-related sustained outages, the Drafting Team tried several approaches but could not find a mechanism in the standard development process to establish a non-zero threshold for outages that was acceptable to FERC staff because Standard revisions to already approved standards may not lead to less emphasis on reliability.**		
Western Area Power Administration, Upper Great Plains Region	Disagree	R4 as proposed would do nothing to improve the reliability of the BES. In fact, we believe that R4 (as currently proposed) would impose significantly more stringent requirements than most Transmission Owners have interpreted FAC-003-1 to require. We believe that if the proposed interpretation would have been offered under FAC-003-1 that there would have be a great backlash against that Standard. It is our believe that current annual certifications of compliance for FAC-003-1 by Transmission Owners don't use "any infringement of the CCZ by any piece of vegetation at any time" as their measure for compliance. It could be argued that this proposal would actually do more to curtail accurate reporting of potential violations. We believe that making an infringement into the CCZ a violation and having that violation carry a six (or seven) figure fine would do more to discourage accurate reporting than any other system under discussion. Making the Transmission Owner prove that an incursion into the CCZ didn't happen would force an inventory of every inch of the R/W which is a gigantic waste of resources. Being tasked with proving that something didn't happen could be compared with our justice system declaring suspects will be considered guilty until they are proven innocent. This is a flawed and blatantly unfair concept and not a productive way of attaining the Purpose stated in this document. Western (UGPR) is disappointed by the "zero tolerance" nature of this document and its interpretation that "any infringement of the CCZ by any piece of vegetation at any time" constitutes a violation. We are not aware of any other NERC standard that is zero tolerance and question why vegetation is singled out to bear the brunt when several other factors could contribute to a system cascading event (i.e. relay problems, system configuration, operator issues, etc). In summation, we believe that a zero tolerance document being applied with "guilty until proven innocent" principles would do much to create an increasingly adversarial relationship between regulators and the industry.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
SERC Vegetation Management Subcommittee (VMS)	Disagree	The concept of the CCZ is useful as a mental model to visualize required vegetation management work. While this is a good conceptual tool to drive consistent terminology and proper vegetation management practices, it remains theoretical in nature and impractical to measure on a span by span basis. The complexity of determining

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		an encroachment into the CCZ is overly burdensome due to the need for survey accuracy measurements and engineering evaluations. In addition, this complexity leads to questions about the ability to audit this requirement. These complexities introduce reliability and audit issues when encroachments into this conceptual area are defined as violations. The SERC VMS believes the Sustained Outage, as defined by other measures in this standard, should be the non-compliance measure. We suggest that the CCZ concept be kept in the technical white paper and that all references to the CCZ be removed from the body of the standard.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Progress Energy Florida	Disagree	The definition of Critical Clearance Zone includes too many academic and theoretical elements. It is impossible to provide evidence that vegetation did not encroach into the Critical Clearance Zone during TVMP cycles. Furthermore, the operations staff performing periodic ground and aerial inspections would need to determine the CCZ for each foot of transmission line to assure compliance with the standard as it is currently written. The CCZ concept can neither be implemented or enforced as written. The CCZ refers to Ratings which is defined in the Glossary of Terms as "The operational limits of a transmission system element under a set of specified conditions." This definition is too broad to be a consistently enforceable term from one utility or region to the next. As it is currently written, no exemption exists for vegetation falling from outside the Active Transmission Line Right of Way into, or lodging in, the theoretical CCZ.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Kansas City Power & Light	Disagree	As proposed, Requirement R4 and corresponding Measure M4 will be highly subjective and impractical for the industry to implement. The determination of a violation due to encroachments into the Critical Clearance Zone will be subjective in nature due to field judgments, is random and not initiated by a known system event. It also will not be feasible for utilities to fulfill R4 requirements to ensure and provide evidence that any encroachments into Critical Clearance Zones have not occurred on their system throughout the year. Requirement R4 is not required since in the remaining requirements of FAC-003-2 contain the principal elements for compliance in ensuring the reliability of the bulk power system related to vegetation management of the transmission system. Specifically, the remaining requirements provide that a transmission vegetation plan be maintained, implemented and regularly reviewed whereby utilities must perform the requisite vegetation clearance work in order to prevent any sustained outages on the bulk power system. A sustained outage due to vegetation is a known, measurable event to which a penalty sanction will be invoked and therefore provides the required impetus for adherence to standard FAC-003-2.Requirement R4 and the associated measure M4 should therefore be removed from the proposed standard

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		language.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Western Area Power Administration, Rocky Mountain Region	Disagree	As discussed in the Technical Reference document and question #11 above, the CCZ is a complicated theoretical envelope surrounding all rated operating positions of the conductor. Its dynamic shape is constantly changing and is contingent upon location within the span. Calculation of the size and shape of CCZ is based, in part, upon the design parameters of the transmission facility. However, as-built or long term maintenance conditions can often diverge from the original design requirements over time. Ground elevations can also change as a result of man made or natural causes from the original design elevations recorded on plan and profile engineering drawings. Consequently, accurate field measurement of the as-built CCZ is extremely problematic and strategies that utilize the calculation of allowable right-of-way tree heights can be hindered by unrecorded deviations from the original design criteria. Allowable tree height strategies also become increasingly more difficult and impractical with increasing extremes in terrain. While the CCZ is a very important concept for an effective vegetation management program it is far to theoretical, dynamic, and impractical to field measure for use as a clear and precise boundary for regulatory purposes. As such, R4 as written should be deleted from the Standards. Further, the requirement to provide evidence of something that has not occurred (no vegetation encroachments of the CCZ) is also impractical. General industry interpretation of R1.2.2 in version 1 of the Standards is that the specific Clearance 2 distance is the precise boundary that is not to be encroached verses the broader area that is ultimately mapped out as the conductor moves through "all rated electrical operating conditions". Only the Clearance 2 distance value is a clear, precise number that can be accurately observed and measured in the field. If there is a persistence to retain the CCZ concept as a requirement within the Standards, the second bullet option above regarding the initiation of the imminent threat process upon discovery of a possible encroachment is the preferred option. Since a potential encroachment into the CCZ is not a violation under this option, exact determination of the CCZ boundary is no longer as essential. Rather, the focus is on triggering mitigation to vegetation problems to prevent outages. However, as with question #11 above, there is still no practical way to determine for regulatory purposes those "potential encroachment" situations that legitimately require initiation of the imminent threat process from those "potential encroachment" situations that do not. Under this option the utility is really motivated to initiate the imminent threat process to avoid an impending outage. As such, the occurrence of an outage becomes the only clear, precise and observable means to determine a Standards violation. A proposed alternative to ensure a level of reliability equal to or better than FAC-003-1 is to retain the Clearance 2 requirement (without the imprecise "all rated electrical operating conditions" language) in combination with the sustained outage requirements of R5, R6 and R7. If an additional margin of safety is determined to be required, industry performance can be adjusted to become more proactive by increasing the minimum Clearance 2 distance to a value greater than the proposed version 2 Gallet equation (table 1) values. Thinking in terms of the

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		CCZ concept, it is obvious that a larger Clearance 2 value translates into a larger CCZ envelope. A larger CCZ envelope in turn triggers mitigation for possible CCZ encroachments sooner.
Response: The SDT thanks you for your comments and proposed alternatives. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Progress Energy Carolinas	Disagree	The definition of Critical Clearance Zone includes too many academic and theoretical elements. It is impossible to provide evidence that vegetation did not encroach into the Critical Clearance Zone during TVMP cycles. Furthermore, the operations staff performing periodic ground and aerial inspections would need to determine the CCZ for each foot of transmission line to assure compliance with the standard as it is currently written. The CCZ concept can neither be implemented or enforced as written. The CCZ refers to Ratings which is defined in the Glossary of Terms as "The operational limits of a transmission system element under a set of specified conditions." This definition is too broad to be a consistently enforceable term from one utility or region to the next. As it is currently written, no exemption exists for vegetation falling from outside the Active Transmission Line Right of Way into, or lodging in, the theoretical CCZ.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Southern California Edison Company	Disagree	Q15: SCE does not agree that proposed R4 was written in the most effective way because it establishes a zero tolerance enforcement policy. SCE agrees that a CCZ incursion should be addressed promptly, but we do not agree that a CCZ incursion is equivalent to a vegetation-to-line contact, or that a CCZ incursion represents an imminent threat of flash-over. As written, proposed R4 would require Transmission Owners to prove that a Critical Clearance Zone incursion has not occurred. Short of a daily ground or aerial inspection of every applicable transmission line, it is clearly impossible for a Transmission Owner to monitor their active Right of Way on a 24/7/365 basis to ensure a CCZ incursion will not or has not occurred. Bearing in mind that even the most robust of Transmission VM programs may occasionally identify an anomalous condition (in or outside the active ROW) that left untreated could lead to a flash-over or vegetation-to-line contact, the identification of such conditions typically occur during scheduled aerial or ground patrols and addressed timely. Of the two alternatives offered, SCE finds the first option (second bullet item) to be the most palatable. However, even that option leaves significant doubt as to practical enforcement, because a Transmission Owner could still be found in violation of two separate requirements (R4 and R5, R4 and R6 or R4 and R7) should a vegetation-to-line contact (resulting in a sustained outage) occur. This situation amounts to regulatory double jeopardy. SCE believes that by any reasonable legal or regulatory measure, requiring a Transmission Owner to prove that a CCZ incursion did not

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		occur is impractical and virtually impossible to enforce in a fair and impartial manner. Further, SCE believes that proposed R4 and corresponding M4 detracts from the purported goal of FAC-003-2 and should be removed.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
SERC OC Standards Review Group	Disagree	The requirement, as written, compels the Transmission Operator to allocate precious resources to ensuring that a vegetation encroachment NEVER will occur on any transmission line, regardless of that line's true importance to maintaining electric transmission system reliability. All lines are not created equal; only those that are involved in IROLs should be held to a zero tolerance standard. R4, if retained, should begin with "Subject to its legal rights," and insert the word "vegetation" between prevent and encroachment. Vegetation, which falls through the Critical Clearance Zone or falls to lodge within the Critical Clearance Zone, should not be included as violations of the Critical Clearance Zone. The concept of the Critical Clearance Zone is useful as a mental model to visualize required vegetation management work. While this is a good conceptual tool to drive consistent terminology and proper vegetation management practices, it remains theoretical in nature and impractical to measure on a span by span basis. The complexity of determining an encroachment into the Critical Clearance Zone is overly burdensome due to the need for survey accuracy measurements and engineering evaluations. In addition, this complexity leads to questions about the ability to audit this requirement. These complexities introduce reliability and audit issues when encroachments into this conceptual area are defined as violations. The SERC OCSRG believes the Sustained Outage, as defined by other measures in this standard, should be the non-compliance measure. We suggest that the Critical Clearance Zone concept be kept in the technical white paper and that all references to the Critical Clearance Zone be removed from the body of the standard. R5, R6, and R7 ensure that version 2 of the standard has reliability requirements equal to version 1; therefore R4 should be removed.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time. The SDT, for clarity, did add the phrase "of Vegetation" as requested.		
Western Utility Arborists		The new requirement in R4 stipulates that the Transmission Owner is in violation if an encroachment of the CCZ occurs at any time. However, the CCZ changes with each foot of the transmission line from the insulator to the mid-span, depending on loading, actual operating temperature, wind loading, ice loading, maximum design rating, maximum operating load, and so on. Further, measure M4 requires that the Transmission Owner has evidence demonstrating there were no vegetation encroachments into the CCZ. To provide evidence demonstrating there were no vegetation encroachments into the CCZ would be an extremely onerous task and an expensive requirement for the Utilities. The Western Utilities strongly supports the alternative to R4 as recommended in the

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		Comment Form (#15), which is to require immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the CCZ, thereby proactively preventing an outage. This means a violation would occur only if the imminent threat process is not successfully implemented. This alternative is essentially the same as R2. Therefore, the Western Utilities recommend removing R4 from the standard entirely.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Florida Power & Light	Disagree	NERC standards require the Transmission Owner certify annually that they are in compliance to the standard for the entire year. Since there is no way that a Transmission Owner could monitor every span of line every minute of every day, Requirement R4 cannot be certified. A Transmission owner can only certify that at the time inspected the system met the specification in the standard and that implementation of its Transmission Vegetation Management Plan maintains these specifications. As stated earlier, the Critical Clearance Zone is difficult to accurately identify in the field and without an outage it would be difficult for an auditing body to find and validate. Requirements R4-R7 are reactive in nature. They are violations after the event has occurred or when the tree - wire relationships are so close that emergency action is the only recourse for the Transmission Owner. The standard needs to drive the Transmission Owner to identify and remove trees threatening the system in a proactive fashion. A Transmission Owner should never be in violation for timely action to remove a threat to the system.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Santee Cooper	Disagree	Recommend replacing the word "prevent" in R4 to "monitor". The first alternative that requires immediate removal of vegetation or immediate implementation of the imminent threat procedure would be a Requirement that could be measured. In addition, if an encroachment is found it needs to be eliminated and the first alternative specifies immediate removal. If R4 is left as written, how can you provide evidence that there has been no encroachments within the Critical Clearance Zone.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		

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Southern Company	Disagree	The Critical Clearance Zone is a concept that adequately describes the salient functionality a Transmission Owner must consider when determining acceptable clearances. However, the practicality of a requirement that forbids even one encroachment in the Critical Clearance Zone presents a problem for not only the field personnel doing the vegetation work, but also the Regional Entity that must enforce the requirement. This zone changes not only from one span to another, it also changes at each location along each span. The reality is that the difference in encroaching into the zone and not encroaching into the zone is a matter of a fractional inch. In order to prove non-compliance or to defend compliance at a particular site, all vegetation work would have to be postponed for survey accuracy equipment and appropriately trained personnel to be brought to the site, measurements and calculation to be made and consequently a determination rendered. This hardly seems worthwhile when the vegetation could simply be cut, the threat removed and the vegetation work could continue on down the transmission line. As stated in a previous comment, there could be many examples given of encroachments into this theoretical zone that would neither threaten the transmission line conductor nor cause a reduction in the capacity of the transmission line. This concept would be better suited to be a “trigger point” that, if found, would be incentive for the Transmission Owner to either take immediate action or ensure future activities are appropriately scheduled and implemented. This action may be as urgent as implementation of the immediate threat procedure or as non-urgent as making sure that the upcoming maintenance on that line is scheduled appropriately. If a sustained outage occurs due to an encroachment, the outage should be the compliance measure.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
E.ON U.S.	Disagree	The concept of the Critical Clearance Zone is useful as a mental model to visualize required vegetation management work. While this is a good conceptual tool to drive consistent terminology and proper vegetation management practices, it remains theoretical in nature and impractical to measure on a span by span basis. The complexity of determining an encroachment into the Critical Clearance Zone is overly burdensome due to the need for survey accuracy measurements and engineering evaluations. In addition, this complexity leads to questions about the ability to audit this requirement. These complexities introduce reliability and audit issues when encroachments into this conceptual area are defined as violations. We believe the Sustained Outage, as defined by other measures in this standard, should be the non-compliance measure. We suggest that the Critical Clearance Zone concept be kept in the technical white paper and that all references to the Critical Clearance Zone be removed from the body of the standard.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		

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Bonneville Power Administration	Disagree	R4 states that the Transmission Owner is in violation of the Standard if the Critical Clearance Zone is encroached upon. The CCZ, as defined by the Standard, changes along the transmission line from the insulator to mid-span, depending on loading, actual operating temperature, wind and ice loading, maximum design rating and operating load, etc. Also, the tandem, Measure M4, requires that the Transmission Owner has evidence demonstrating that there has been no vegetation encoachments in the CCZ along its transmission system. In order to meet the letter of the Standard, that is to provide evidence that no encroachments in the CCZ have occurred under all manner of these fluid environmental and operating conditions, the Transmission Owner would have to employ the highest level of modeling technology available, which would seem to be LiDAR technology. The standard should not be written in such a manner so that it requires, by all intent and purpose, a Transmission Owner to acquire a particular technology. BPA recommends that the Alternative represented by "the second bullet" above, be used rather than R4 in its present state, or that R.4. be simply dropped and R1.4 modified to state that the imminent threat procedures include immediate removal of encroachments into the Critical Clearance Zone. Also, the term "immediate" implies instantaneous response. The use of another term is recommended, such as "as immediate as human health and safety considerations allow, in order to prevent the possibility of flashover".
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Public Service Electric and Gas Company	Disagree	An additional clarifying exception in the footnotes to R4 consisting of a tree that is located off of the transmission owner's right of way falling into the CCZ should be added to the encroachment exceptions. Transmission owners should not be found in violation of the standard for falling vegetation located off of the TO's property.
Response: The SDT thanks you for your comments. The SDT has added the exception you requested. Note that the exception applies to any falling vegetation regardless of its location. **3. Brief encroachment into the Minimum Vegetation Clearance Distances listed in Attachment 1 resulting from falling vegetation.**		
FirstEnergy	Disagree	Providing evidence to prove that there were no encroachments of the CCZ is difficult at best. An occurrence of an encroachment does not necessarily translate to an outage. The CCZ is dynamic and difficult to measure exactly from span to span and day to day and is dependent on environmental and line conditions. The costs to comply with this requirement as written are difficult to justify considering that reliability may not be improved at all. FirstEnergy believes that the first alternative above should be used and is a more logical approach from both a reliability and compliance standpoint. Furthermore, since the first alternative is already covered by the currently proposed wording of R2, the only changes needed to the standard are to remove the proposed R4 and M4 and re-number the requirements.

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Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
MRO NERC Standards Review Subcommittee	Disagree	The MRO believes R4 should be eliminated as vegetation contacts are covered in R5 and R6. A violation should only occur with a vegetation contact. Assessing a violation and fine for a potential reduction in system reliability is not correct. Actual contacts that trip a transmission element have some measurable impact on system reliability even if it is slight.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Midwest ISO Stakeholders Standards Collaborators	Disagree	The second bulleted alternative above is the best approach, but it should be improved by changing the imminent threat trigger from "encroachment of the CCZ" to "encroachment within some observed, field distance that is a multiple of the Gallet distances referenced in Table I". We have recommended changes to accomplish this in Requirement R2 (see our response to Question #11 above), and R4 should simply be deleted. While the CCZ is valuable to understanding the movement of conductors, it cannot be readily applied in the field. This field application challenge is noted in the Technical Reference Document (pages 29 & 30).The way R4 is currently stated, the Transmission Owner would be in violation of R4 for any CCZ encroachment not due to natural disasters or human or animal activity. This would include a tree falling from outside the right of way corridor that passes through the theoretical CCZ. Furthermore, Transmission Owners would be required to self-certify compliance with R4, and we don't think there's any way to do that. Clearly the approach of assessing violations for CCZ encroachment is unworkable. Likewise, the third alternative listed above is untenable. The tiered approach could have a mitigating effect on violations, but it would require the same inspection effort and postponement of vegetation management that makes the first alternative unworkable. Both the first and third alternatives would require very significant additional expenditures for surveys and documentation in an impossible attempt to certify compliance - money that would be better spent controlling vegetation.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time. The proposed standard revision specifies the MVCD as a starting point and TO's may apply multiples at their own discretion in order to achieve their TVMP objectives and adhere to applicable safety standards.		
SERC Compliance Staff	Disagree	The concept of the Critical Clearance Zone is useful as a mental model to visualize required vegetation

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		management work. While this is a good conceptual tool to drive consistent terminology and proper vegetation management practices, it is impractical to measure on a span by span basis. The complexity of determining an encroachment into the Critical Clearance Zone is overly burdensome due to the need for survey accuracy measurements and engineering evaluations. While it may be a technically sound approach to designate the clearance zone to be tied to the conductor movement envelope as found in the NESC, this results in a banana-shaped zone that is difficult to substantiate in the field by entity and compliance personnel. We suggest that the Critical Clearance Zone concept be kept in the technical white paper and that all references to the Critical Clearance Zone be removed from the body of the standard.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
ITC HOLDINGS	Disagree	First, it's impossible to determine that no encroachments into the CCZ have occurred at any time and determination of the CCZ from the field perspective is problematic. The standard is ambiguous and it seems like clear cutting is the underlining message that is wanted. Determining an encroachment into the CCZ is problematic due to the need for survey accuracy measurements and engineering evaluations. This will also lead to questions about the ability to audit this requirement. The CCZ changes in size and shapes continuously in each and every span and will be difficult to monitor. This would require field personnel to spend numerous hours estimating and attempting to measure potential encroachments of the CCZ. The way R4 is currently written the Transmission Owners would be required to self-certify compliance with R4, and which we don't think this is possible. This will lead to audit issues with more scrutinizing and potentially more penalties or fines. It is important to recognize that the ultimate goal of the standard is to ensure that vegetation management is conducted in order to maintain an adequate level of reliability, and not to precisely measure clearance zones. Alternative 2 would be the most logical choice, depending on easement/legal rights, with changes that would eliminate any reference to a trigger point into the encroachment zone of the CCZ to; measuring encroachment to a fix distance (Gallet tables) observed by field personnel
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Tennessee Valley Authority	Disagree	TVA recommends that R4 be removed from this standard. Since this is a "zero tolerance" standard with substantial penalties for controllable vegetation related outages there is an overwhelming incentive for the Transmission Owner to proactively perform inspections, preventative maintenance, inpections and corrective maintenance to prevent potential outages. As such, R4 does not add any value to improving reliability while causing numerous

Organization	Agree?	Question 15 Comment
		unresolvable problems.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Exelon	Disagree	The first bullet is unworkable in the real world. It will be virtually impossible to prove that "no encroachments of the CCZ have occurred anywhere at any time during the compliance period". The effort to do this will not enhance reliability. In fact, in may harm reliability by requiring unnecessary investments and O&M expenditures that could be better spent on real reliability enhancements. Exelon agrees, subject to the development of a workable definition of the CCZ, that the second bullet is the preferred approach.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Central Maine Power Company	Disagree	Central Maine Power Company suggests the second alternative to R4 as recommended above, which is to require immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the critical clearance zone, thus preventing an outage. This alternative is similar to R2, therefore R4 may not be required.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
American Electric Power (AEP)	Disagree	AEP disagrees with the proposed requirement that violations be automatically declared if the CCZ is encroached. Instead, AEP would support a standard utilizing the first alternative proffered in these comment questions. While the CCZ is an interesting theoretical concept, it is not realistically feasible in the field to implement a concept that depends on accurate measurements and calculations. Further, the proposed requirement offends common notions of reliable maintenance methods, because it demands that forestry crews stop work if they see a potential encroachment and that surveyors and engineers be brought in to take detailed measurements and perform complex calculations to determine whether an encroachment has in fact occurred. The need for a reliable transmission grid would be much better served by a standard utilizing the first alternative, in which no violation occurs in the event of an encroachment as long as the TO implements its imminent threat procedure and removes the vegetation. While seemingly technically appealing, the CCZ concept is fraught with implementation difficulties. It should not be used as a Pass/Fail zero-tolerance decision point to determine whether a violation has occurred.

Organization	Agree?	Question 15 Comment
		After all, a zero-defect condition has not been achieved in many other aspects of electric utility operation. For instance, the utility industry attempts every year to conduct its business without any workplace deaths, yet deaths occur every year. Many millions of dollars are spent by North American utilities to promote safety programs and safe work procedures, but some work-related vehicle accidents and personal injuries still occur. Also, utilities aggressively investigate electric switching errors and have instituted rigorous dispatcher-training programs, but a few switching errors still occur. For an industry in which billions of stems of vegetation must be managed, even a high six-sigma level of quality would still result in a few cases annually of imperfectly managed vegetation. It is unreasonable to expect zero-tolerance perfection with the CCZ concept. Also, with the way R4 is worded, a tree falling from outside the right of way would result in a violation if it passed through the CCZ, whether it resulted in an outage or not. It is not appropriate to place a burden on the TO for such circumstances outside the TO's control. As R4 is written, it appears that there is no way that a TO could certify at the end of the year that it has maintained a CCZ free of encroachments, even if no outages occurred. AEP believes a more effective and reliability-centered approach would be one where TOs are expected to implement their imminent threat procedure if vegetation is encroaching upon the Gallet equation distance. If TOs act accordingly and remove the vegetation without incurring an outage, then they would not be in violation. However, if the TOs knew of vegetation encroaching upon the Gallet equation distance but failed to implement their imminent threat process, they would be in violation and be obliged to report the event.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Platte River Power Authority	Disagree	This requirement should be removed completely. It is too stringent and it is impossible to prove compliance through documentation. Encroachemnt of Clearance 2 (or CCZ) should be addressed in the imminent threat procedure.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
City of Tallahassee	Disagree	VEHEMENTLY DISAGREE! The purpose of the standard is to prevent vegetation related outages. A violation should occur if an outage occurs. As written, R4 and M4 would be impossible to prove or disprove. It is not like we can get up there with a tape measure and measure it. R2 requires action if the CCZ is "approached". This is undefined and subject to a myriad of interpretations. Evidence is hard enough to obtain to the satisfaction of the Compliance Monitor. To require sufficient evidence to prove that something didn't occur is a tremendous burden and is not a wise expenditure of vegetation management dollars. Let us spend the money on trimming and not on paperwork. As an alternative replace "encroachment within the Critical Clearance Zone" with "vegetation caused

Organization	Agree?	Question 15 Comment
		outages". This would allow the same exceptions and is much easier to prove or disprove with a breaker operation. Although this would result in the cause of every breaker operation being tracked, it is a tangible evidence requirement and leaves very little room for interpretation. The levels of fines have already shown that vegetation management is a serious standard and we had better comply.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Northern Indiana Public Service Company	Disagree	It will be impossible for a T.O. to provide "evidence" that no encroachments of the C.C.Z. occurred at any time during the year. This approach will be a compliance nightmare and is unworkable. How does one prove this never happens? You can't monitor every span of every line at all times. Obviously, whenever a T.O. has a preventable outage, that should be a violation. To address the issue of preventing outages before they occur and penalizing T.O.'s who don't take proper steps to prevent them, I prefer the approach of immediate removal of threatening vegetation that encroaches within a "threat trigger/action threshold" clearance distance per the T.O.'s formal imminent threat procedure. This "threat trigger/action threshold" clearance would be established by the T.O. and be a specific requirement under a revised FAC-003.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Tampa Electric Company	Disagree	This is a good start. The Critical Clearance Zone (CCZ) is a very real and practical concept; however, it is not transferable to field conditions. This could result in a "fill in the blank" standard relative to what the Critical Clearance Zone will be in terms of distance. As I read this, it will be a sliding scale from insulator to mid span and back for each designated line voltage. The max wind speed to be used and other assumptions behind the determination of this zone may be as involved a Gallet's formula. This will lead to complications during operational inspection and verification of these clearances.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Orange and Rockland Utilities Inc.	Disagree	We believe that R4 is not the most effective way to achieve the purpose of the Standard. As previously stated the CCZ and encroachments of it are generally not possible to identify in the field without taking precise measurements. The CCZ changes in size and shape continuously throughout each and every span. In many

Organization	Agree?	Question 15 Comment
		cases the CCZ can be very large, and the position of the conductor with respect to encroaching vegetation within the CCZ can be relatively far apart. Such cases would typically not be identified as encroachments of the CCZ by visual inspections. Only those instances where the vegetation is significantly overgrown would be readily identifiable. R4, as written presents a problem in terms of compliance, certification of compliance, and auditing because precise measurements of every span are impractical and costly to perform. Certification of compliance would require field personnel to spend valuable time estimating and attempting to measure potential encroachments of the CCZ. R4 does not provide incentive for Transmission Owners to deploy modern technology that is better able to identify encroachments of the CCZ with a reasonable amount of accuracy, such as ALS and LIDAR which are described in the response to Question 11. In fact R4 might provide an incentive not to utilize this technology because Transmission Owners who identify encroachments using ALS which would otherwise not have been identified would be in violation of R4. Transmission Owners that choose to be less proactive often would not identify such encroachments and would be at less risk of violating R4. The effect could be less frequent use of ALS and other technology that may emerge. This would result in fewer problems being identified, a small percentage of which may not be discovered until they result in a line trip. We believe that the best way to achieve the purpose of this Standard is to encourage proactive behavior which prevents vegetation-related outages throughout the entire industry. R4 does not achieve this in the most effective way. We recommend the following: Eliminate encroachment of the CCZ as a violation of R4. Require Transmission Owners to immediately implement the imminent threat process defined in R1.4 when they identify instances where vegetation has grown within a specific distance as described in the response to Question 11 regarding R2. This would essentially combine R2 and R4.Require Transmission Owners to report to the Regional Entity any instances where the imminent threat process was implemented due to a vegetation-related clearance encroachment. This would add a reporting requirement for Transmission Owners. Require Regional Entities to perform additional audits of Transmission Owners that exceed metrics for vegetation-related clearance encroachments. The metrics should be established in the Standard based upon 1000 circuit miles of applicable lines. This would add an additional requirement for Regional Entities. Modify R5, R6, and R7 to include preventing momentary outages as well as Sustained Outages. We believe that this concept would result in a more rigorous standard because of the additional requirements, but would focus the industry's attention in a more effective fashion. We believe it would result in fewer vegetation-related interruptions and a higher level of reliability soon after implementation, and would therefore best support the purpose of the Standard.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time. **The SDT very carefully and thoroughly examined the merits, disadvantages, ease and difficulties of assessing momentary outages as a violation, and chose to address this issue with the language in R4.**		

Organization	Agree?	Question 15 Comment
American Transmission Company	Disagree	While the CCZ is valuable to understanding the movement of conductors, it cannot be readily applied in the field. This field application challenge is noted in the Technical Reference Document (pages 29 & 30).The way R4 is currently stated, the Transmission Owner would be in violation of R4 for any CCZ encroachment not due to natural disasters or human or animal activity. This would include a tree falling from outside the right of way corridor that passes through the theoretical CCZ. Furthermore, Transmission Owners would be required to self-certify compliance with R4, and ATC does not think there is a practical way to do that. Clearly, the approach of assessing violations for CCZ encroachment is unworkable. ATC believes that R4 should be deleted.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Xcel Energy	Disagree	The way this requirement is written may require a utility to prove a negative. In other words, prove that we did not have trees encroaching into the CCZ at any time. This is impossible to prove. We propose the following language: ?The TO shall not have a encroachment within the CCZ which was not dealt with by utilizing the imminent threat procedure before experiencing a Sustained Outage, with the following exceptions 1) Encroachment of the CCZ that result for natural disasters 2) Encroachment of the CCZ that result from human or animal activity."
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Ameren	Disagree	The second bulleted alternative above is the best approach, but it should be improved by changing the imminent threat trigger from "encroachment of the CCZ" to "encroachment within some observed, field distance that is defined in the Plan. This would allow Transmission Owners to define for field personnel a CCZ that accomplishes some multiple of the Gallet distances referenced in Table I" but is easy to determine and apply. We have recommended changes to accomplish this in Requirement R2 (see our response to Question #11 above), and R4 should simply be deleted. While the CCZ is valuable to understanding the movement of conductors, it cannot be readily applied in the field. This field application challenge is noted in the Technical Reference Document (pages 29 & 30).The way R4 is currently stated, the Transmission Owner would be in violation of R4 for any CCZ encroachment not due to natural disasters or human or animal activity. This would include a tree falling from outside the right of way corridor that passes through the theoretical CCZ. Furthermore, Transmission Owners would be required to self-certify compliance with R4, and we don't think there's any way to do that. Clearly the approach of assessing violations for CCZ encroachment is unworkable. Likewise, the third alternative listed above is untenable. The tiered approach could have a mitigating effect on violations, but it would require the same

Organization	Agree?	Question 15 Comment
		inspection effort and postponement of vegetation management that makes the first alternative unworkable. Both the first and third alternatives would require very significant additional expenditures for surveys and documentation in an impossible attempt to certify compliance - money that would be better spent controlling vegetation.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Nebraska Public Power District	Disagree	NPPD disagree with an encroachment being a violation. A lot of time would need to be spent to determine if an encroachment occurred and in a self regulating environment, reporting would be minimal if any. The Transmission Owner would be in violation for any non natural event. Even a tree falling into the ROW passing through CCZ would be in violation of R4. Difficult at best to enforce. We need to spend time keeping the ROW cleared and less time inspecting for possible encroachments.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Long Island power Authority	Disagree	The Standard is about preventing outages and having an effective program. An effective program should allow for the identification of a threat and the removal of the threat prior to a vegetation caused outage. I prefer alternative 2. If a vegetation caused outage should occur or if the Regional Entity determines a violation occurred based on a compliance investigation then the entity is in violation of this requirement.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Disagree	The wording appears too strong. Who can predict the unforeseen circumstances that inevitably arise. If the standards require the reporting of encroachments, the ensuing report can help determine if the Transmission Owner did everything reasonable to avoid the problem. It seems like the standard should be written to require the Transmission Owner to do everything reasonable to avoid the problem. A judgment call would still be needed to evaluate the performance.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		

Organization	Agree?	Question 15 Comment
Manitoba Hydro	Disagree	Manitoba Hydro asserts that the reliability of the system is measured by outage, not by the possibility of an outage, and therefore if the overall vegetation management system (plan-patrol-discover-mitigate) is effective in preventing an outage, then the reliability of the system has been maintained, and the intent of the reliability standard achieved. Therefore, we propose that the second bullet above is the preferred alternative, and that R2 and R4 be combined as the violation of R4 would then imply a violation of R2.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Consumers Energy Company	Disagree	The CCZ does not provide adequate clearance and the imminent threat procedure if successfully implemented only works IF YOU KNOW ABOUT THE VEGETATION THAT THREATENS THE CCZ which cannot be ensured with yearly inspections. Consumers Energy believes that the Clearance 2 distances in FAC-003-1 provide more reliability than the CCZ proposed in this draft or any of the alternatives disused above.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Pacific Gas & Electric Co.	Disagree	PG&E believes a "minimum clearance distance" or "do not encroach zone" is a critical element of this standard and necessary to achieve the stated purpose of preventing vegetation caused outages. Preventing vegetation encroachments will prevent outages. However, PG&E disagrees with using the CCZ as a minimum clearance requirement because it is ambiguous and subject to wide variations and interpretation. CCZ is a good concept to aid in understanding movement of conductors but is a theoretical calculation and would be very difficult if not impossible to enforce. PG&E suggests using a clearly defined distance such as Gallet equation plus a safety margin to assure there is no chance of spark over. Two times Gallet would be a reasonable clearance requirement to assure a spark over does not occur and eliminate the ambiguity of the CCZ as the "do not encroach zone".
Response: The SDT thanks you for your comments. The SDT discussed the Gallet plus alternative suggested by PG&E. Due to the tremendous variation of design standards, the team decided that the decision as to how much a margin for error to use belonged to the individual TO. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time. The threat of a violation is believed sufficient to motivate a Transmission Owner to maintain a larger clearance.		

Organization	Agree?	Question 15 Comment
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Disagree	The new requirement in R4 stipulates that the Transmission Owner is in violation if an encroachment of the CCZ occurs at any time. However, the CCZ changes with each foot of the transmission line from the insulator to the mid-span, depending on loading, actual operating temperature, wind loading, ice loading, maximum design rating, maximum operating load, and so on. Further, Measure M4 requires that the Transmission Owner has evidence demonstrating there were no vegetation encroachments into the CCZ. These requirements may result in having to LIDAR the lines annually, to prove that trees have not encroached upon the CCZ. This would be an extremely onerous and expensive requirement for utilities. NV Energy strongly supports the alternative to R4 as recommended in the Comment Form (#15), which is to require immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the CCZ, thereby proactively preventing an outage. This means a violation would occur only if the imminent threat process is not successfully implemented. This alternative is essentially the same as R2. Therefore, we recommend removing R4 from the standard entirely.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
San Diego Gas & Electric	Disagree	The new requirement in R4 stipulates that the Transmission Owner is in violation if an encroachment of the Critical Clearance Zone (CCZ) occurs at any time. However, the CCZ changes with each foot of the transmission line from the insulator to the mid-span, depending on loading, actual operating temperature, wind loading, ice loading, maximum design rating, maximum operating load, and so on. Further, Measure M4 requires that the Transmission Owner have evidence demonstrating there were no vegetation encroachments into the CCZ. These requirements may result in having to LIDAR the lines annually to prove that trees have not encroached upon the CCZ. This would be an extremely oerous and expensive requirement for utilities. We strongly support the alternative to R4 as recommended in the Comment Form, which is wto require immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the CCZ, thereby proactively preventing an outage. This means a violation would occur only if the imminent threat process is not successfully implemented. This alternative is essentially the same as R2. Therefore, we recommend removing R4 from the standard entirely.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Hydro One Networks Inc.	Disagree	A statement is needed that this requirement applies to the active right of way. Outside of the active right of way there is no guarantee that this can be achieved. As noted in the question above, it may be very difficult with the

Organization	Agree?	Question 15 Comment
		first alternative to provide adequate evidence that no encroachment had occurred over the compliance period, as the situation is very difficult to assess along each span to the accuracies (1/100 of a foot) spelled out for the CCZ. It may be more meaningful that the Transmission Owners be able to demonstrate processes, methodologies and actions that can support that vegetation has not entered the CCZ. Another alternative for R4 could then be: Each Transmission Owner shall demonstrate that adequate actions and processes are in place to prevent vegetation from entering the CCZ. The effectiveness of the process can then be evaluated based on methods used for field assessment and performance, i.e., outages and imminent threat reporting. It appears that the second alternative noted above can be combined with R2. It is not clear why there needs to be a separate requirement. Hydro One is not in favour of alternative 3, as this would create added administration with a situation that will be difficult to prove to the accuracy required. LIDAR may be the only means available to provide evidence of a quality needed to produce meaningful statistics, and in many cases this may not be the most efficient use of the limited funding that is available.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Edison Electric Institute	Disagree	Encroachment without a Sustained Outage should not be construed as a violation. The proposed R4 requirement should be removed. EEI strongly believes that this requirement, if approved, is unenforceable. The alternative, to require implementation of the imminent threat procedure, should be considered as a practical approach. In particular, this concern applies to a requirement to prove that no encroachments have existed. This will require extensive work by field personnel, who will be required to make subjective judgments. In addition, determining actual clearance zones in the field would require a span-by-span analysis to be conducted with the rigor of survey level measurements. Calculations made to determine the clearance zones are based on undefined terms and subject to wide variation. Enforcement authorities will be required to make interpretations. EEI believes that the costs of conducting such work will not deliver sufficient benefit to warrant the requirement. Ultimately, there is no basis for determining whether the theoretical clearance zones included in the proposed standard will increase, or even maintain, an adequate level of reliability as provided by the existing standard.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Consolidated Edison Company of New York (CECONY)	Disagree	CECONY disagrees with R4 as currently written. As mentioned in the response to Question 15, performing a field measurement of the CCZ and a field measurement of the vegetation encroaching into the CCZ are complicated, time-consuming efforts. As the CCZ changes along the conductor, so too may the Active ROW dimensions, the vegetation clearances at multiple points, and elevation levels to name a few. Certifying compliance that no

Organization	Agree?	Question 15 Comment
		encroachments have occurred would be very difficult for auditors and field inspectors. Modern laser technology would have to be deployed to take these measurements and CECONY is concerned that, if an encroachment of the CCZ constitutes a violation, utilities would not consider investing in this technology knowing that multiple violations could potentially be found within a single span. Enhanced reliability is achieved when utilities invest in the best available technology and perform proactive inspections on their systems but, as written, R4 would not effectively motivate a utility to follow through with these initiatives. We recommend that the term 'momentary outage' or the phrase 'all outages' be used in R5, R6, and R7 instead of 'Sustained Outages' to avoid confusion throughout the industry. Momentary outages identify a potential failure of the utility's vegetation management program and stating it directly in the Standard clearly sends the message to utilities that all vegetation outages are unacceptable. In summary, we do not agree that encroachments are violations but we do recommend that when a utility identifies vegetation-related imminent threats and takes immediate action, they report this to their Reliability Coordinator. The Reliability Coordinator (RC) could then identify the utilities that have had multiple issues or have exceeded acceptable pre-established reporting limits which, in turn, would help the RC prioritize auditing efforts. This, in our opinion, would enhance reliability more effectively.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time. **The SDT very carefully and thoroughly examined the merits, disadvantages, ease and difficulties of assessing momentary outages as a violation. The result of that effort led to the more precise and field observable aspects of R4. It should be noted that by their very nature the exact causes of "momentary outages" are very challenging to determine and will vary widely from utility to utility. The SDT did not find that such variability was appropriate for a reliability standard, and chose to address this issue with the language in R4.**		
Arizona Public Service Company	Disagree	APS agrees with alternative one. The new requirement in R4 stipulates that the Transmission Owner is in violation if an encroachment of the CCZ occurs at any time. However, the CCZ changes with each foot of the transmission line from the insulator to the mid-span, depending on loading, actual operating temperature, wind loading, ice loading, maximum design rating, maximum operating load, and so on. Further, Measure M4 requires that the Transmission Owner has evidence demonstrating there were no vegetation encroachments into the CCZ. These requirements may result in having to LIDAR the lines annually, to prove that trees have not encroached upon the CCZ. This would be an extremely onerous and expensive requirement for utilities. APS strongly supports the alternative to R4 as recommended in the Comment Form (#15), which is to require immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the CCZ, thereby proactively preventing an outage. This means a violation would occur only if the imminent threat process is not successfully implemented. This alternative is essentially the same as R2.

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		Therefore, APS recommends removing R4 from the standard entirely.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Baltimore Gas & Electric Company	Disagree	One concern with the proposed wording is that the verbiage seems to provide a loophole that will count any fallen tree, or tree with the potential to fall from inside or outside of the R/W (that doesn't meet the criteria in footnotes 4 & 5) that passes or could pass through the CCZ, and that may or may not cause an outage, would qualify as a violation in the std. There is no other language that I can detect in the std. that counters this point. Determination of whether or not a fallen tree, or tree with the potential to fall would qualify would be predicated upon height measurements of the fallen or standing tree(s) relative to the CCZ at max. engineered sag. An alternative wording suggestion is: "Each Transmission Owner shall prevent encroachment within the Critical Clearance Zone of it's applicable lines associated with trees that meet the criteria for grow-ins from on or off the Active right-of-way. Fall-ins from inside or outside of the active right-of-way are not applicable to this sub-requirement." If the occurrence is a violation, reporting of the incident will be an ethical issue and rely on the honesty of the inspector or whomever finds the problem. If it's not a violation, it will be more likely that the incident will be reported and can be treated as "Near Miss' reports are with respect to safety incidents - they provide valuable input to help forestall future more serious incidents. Consequently, I recommend that no violation occur as long as the 'Imminent Threat Procedure' is implemented. Further, if there is no violation associated with Imminent Threat Procedure implementation, I would suggest that falling or standing trees originating from within the active right-of-way that encroached or could encroach in the CCZ be added to the requirement to enhance the 'Near Miss' data pool.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Duke Energy Corporation	Disagree	The second bulleted alternative above is the best approach, but Duke believes it should be improved by changing the imminent threat trigger from "encroachment of the CCZ" to "encroachment within some observed, field distance that is a multiple of the Gallet distances referenced in Table I". We have recommended changes to accomplish this in Requirement R2 (see our response to Question #11 above), and R4 should simply be deleted. While the CCZ is valuable to understanding the movement of conductors, it cannot be readily applied in the field. This field application challenge is noted in the Technical Reference Document (pages 29 & 30).The way R4 is currently stated, the Transmission Owner would be in violation of R4 for any CCZ encroachment not due to natural disasters or human or animal activity. This would include a tree falling from outside the right of way corridor that passes through the theoretical CCZ. Furthermore, Transmission Owners would be required to self-certify compliance with R4. The technological requirements for accurately certifying compliance would be impossible to

Organization	Agree?	Question 15 Comment
		administer. Clearly the approach of assessing violations for CCZ encroachment is unworkable. Likewise, the third alternative listed above is untenable. The tiered approach could have a mitigating effect on violations, but it would require the same inspection effort and postponement of vegetation management that makes the first alternative unworkable. Both the first and third alternatives would require very significant additional expenditures for surveys and documentation in an impossible attempt to certify compliance - money that would be better spent controlling vegetation.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
CenterPoint Energy	Disagree	It is not reasonable to expect Transmission Owners to devote resources, both human and financial, to prove that vegetation never encroached into the Critical Clearance Zone, anytime-anywhere. R4 and M4 should be deleted.R2 and M2 are sufficient in ensuring a level of reliability equal to or better than FAC-003-1 with some minor wording changes to adopt similar wording of the alternative to R4 that was considered by the drafting team that includes "immediate implementation of the imminent threat procedure" for imminent threats of a vegetation related Sustained Outage in lieu of a nebulous "encroachment of the Critical Clearance Zone". According to the Technical Reference, it is "nearly impossible to field correlate and accurately 'superimpose' the Critical Clearance Zone around the conductor". It not likely that the Transmission Owner will know when the Critical Clearance Zone is approached through field observation. The previous Clearance 2 provided for a specific radial clearance from the conductor that was much easier to observe. (See comments to Q3 above.)
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Entergy Services	Disagree	1. Entergy believes that outages caused by vegetation are the most reasonable and objective measures for a violation which is not consistent with the proposed R4. See additional comments in section 16 related to R5, 6, and 7. 2. If R4 remains, Entergy proposes that the most reasonable approach to this requirement is a variation of the second bulleted option. This variation would include wording clarifying that only known encroachments of the Critical Clearance Zone would be considered violations. Entergy is willing to include failures to enact the imminent threat process (which is really a violation of R2) and also known vegetation inside the Critical Clearance Zone. This variation should continue to include the exceptions for natural disaster and human activities. 3. Determining objective, quantifiable encroachments into the Critical Clearance Zone is very challenging in field operations because such determination may require a degree of accuracy only obtainable using survey equipment

Organization	Agree?	Question 15 Comment
		or other sophisticated, costly measuring devices. 4. Entergy is concerned about the challenges of uniform audit ability due to noted uncertainties and the statement of absolute criteria that have to be shown in the negative. If the first bullet option is approved for R4, Entergy suggests the sentence “Evidence will be required to prove that no encroachments of the Critical Clearance Zone have occurred anywhere at the any time during the annual compliance period” be deleted. It is very difficult in regulatory terms to attest that no vegetation has ever crossed the Critical Clearance Zone during the time period being reviewed given the wide range of potential conditions that may not have been detected or even been detectable unless the conditions afforded direct observation. Too many assumptions would have to be made for an entity to self certify to this requirement. If R4 is implemented as stated, those assumptions need to be stated and clarified. 5. If any version of R4 is approved, Entergy suggests that the standard include an exception for trees falling from off the right of way and encroaching the Critical Clearance Zone. For example, a tree that falls from off the right of way. During the fall towards the conductor, the tree could possibly break the Critical Clearance Zone without causing an outage or even a threat of an outage yet still be a violation of the proposed standard. 6. If the second bulleted item is approved, it should be altered to read “a violation would have occurred only if no vegetation imminent threat process was initiated.” 7. Entergy does not feel the third bulleted item is adequately defined to use as a requirement in the standard at this time. 8. Conditions for blow-out, in the development of the Critical Clearance Zone, need to be defined in the standard. Their inclusions, in the white paper only, are not appropriate, as well.
Response: The SDT thanks you for your comments and suggested alternatives. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time. The SDT addressed your item 5 in subpart 3 in R4. This exception would apply to any falling vegetation outside the right of way or inside the right of way.		
Pepco Holdings, Inc	Disagree	As discussed in our response to Q11, the concept of encroachment into the Critical Clearance Zone is flawed. It is enforceable almost exclusively through self reports. R5, R6 and R7 provide all incentives for the TO to follow its inspection and maintenance plans, and R2, if properly written to remove references to the Critical Clearance Zone provides additional incentives. R4 is not needed and should be deleted. PHI is puzzled where this concept came from. Nowhere in Order 693 is this concept discussed.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon		

Organization	Agree?	Question 15 Comment
substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time. The concept of the CCZ was originally intended to provide an area that could be used to produce a metric for less than “zero tolerance” however that did not materialize.		
JEA	Disagree	As written, demonstration of compliance may not be feasible and would certainly be prohibitively expensive, consuming resources better spent managing vegetation. In general, putting entities in the position of proving something didn't occur is exptremely difficult and burdensome, without really aiding reliability. If the incident was significant, the region would know about it, and investigations can be pursued, if warranted. The first alternative requiring implementation of the imminent threat procedure is a better choice.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Salt River Project	Disagree	Disagree with R4 as it is written. The new requirement in R4 stipulates that the Transmission Owner is in violation if an encroachment of the Critical Clearance Zone occurs at any time. However, the Critical Clearance Zone changes with each foot of the transmission line from the insulator to the mid-span, depending on loading, actual operating temperature, wind loading, ice loading, maximum design rating, maximum operating load, and so on. See additional comments in Comment #18 below. Furthermore, Measure M4 requires that the Transmission Owner has evidence demonstrating there were no vegetation encroachments into the Critical Clearance Zone. To provide evidence demonstrating there were no vegetation encroachments into the Critical Clearance Zone would be an extremely onerous task and an expensive requirement for the utilities. We strongly support changing this to the 1st alternative written in Comment #15 "One alternative to R4 required immediate removal of the vegetation or immediate implementation of the immenent threat procedure upon discovery of a possible encroachment of the Critical Clearance Zone, thereby proactively preventing an outage. A violation would have occurred only if the immenent threat process was not successfully implemented." This alternative is essentially the same as R2, therefore, we recommend removing R4 from the standard entirely.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Northeast Utilities	Disagree	First - the determination of the CCZ is highly problematic in the field. Second - it is impossible for any utility to certify that no encroachments have occurred at any time unless a utility has completely removed all potentially interferring vegetation on all areas of their transmission system. If the standard is to clear-cut and maintain a tree free right of way, the standard should say so. To determine if vegetation may have violated the CCZ the inspector

Organization	Agree?	Question 15 Comment
		must know at the time of the inspection the ambient temperature, the wind speed, the loading of the line and the actual distances between the vegetation and conductors. Then, the information must be compared to possible extreme operating levels of the line under all conditions to know if the vegetation may violate the CCZ. As stated - it is improbable that this could accurately be performed in the field as the data changes within each segment of a span's length. The first alternative provides the most effective means of addressing encroachment of the CCZ - having an encroachment is not a violation - knowing there is an encroachment and not correcting the problem would be a violation. Implementing the imminent threat procedure and correcting the problem is a more effective approach. Having a zero tolerance for encroachments of the CCZ under all situations and operating conditions would sub-optimize the use of resources. No actual event may have occurred on the system, yet the utilities will be in violation just for a possible or potential problem that even under extreme operating conditions may not actually occur. It would be best if the violations were limited to "known encroachments" (not "possible encroachments") such as would occur if a line were to trip due to vegetation contact, or if there is evidence of any burns. If no action was taken on known encroachments to correct the problem (such as implementation of the imminent threat procedure) then a violation will have occurred. It is doubtful that any utility will be able to certify that at no time has vegetation encroached into the CCZ. Utilities will have to spend an untold amount of resources to verify that there have not been any encroachments during a compliance period - instead of using these resources more effectively in taking proactive measures to manage and control encroaching vegetation. As written, any encroachment into the CCZ is considered a violation of FAC-003-2 (R4). There are exceptions provided for encroachments due to natural disasters and human or animal activity. There is no exception for encroachments due to the failure of a tree(s) outside of the active transmission line ROW. Based on R4, a trip and reclose of a transmission line (no outage) is a violation even if the tree is outside of the active right-of-way; whereas per R6 and R7, a line outage would not be a violation if the tree was outside of the active right-of-way. As written - this is not clear - there should be exceptions to allow for trees falling into the CCZ (and into the active transmission line right-of-way) from outside the limits of the active transmission line right-of-way. Also - how are violations of the CCZ requirement to be reported - there is no provision for the reporting process and requirements (specifics on the type of violation). Will this be addressed in the Compliance Section yet to be added?
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Hydro-Quebec Transenergie (HQT)	Disagree	The purpose of the standard is "To improve the reliability of the Bulk Electric System by preventing vegetation related outages that could lead to Cascading". We believe that R4 is not the most effective way to achieve this purpose because it does not provide incentive for Transmission Owners to take advantage of modern technology, such as aerial laser survey (ALS) using Light Detection and Ranging technology (LIDAR), that is capable of accurately identifying vegetation which is approaching the CCZ or has encroached into it. In fact R4 provides an incentive not to utilize this technology because Transmission Owners who identify encroachments would be in

Organization	Agree?	Question 15 Comment
		violation of R4 for each identified encroachment. On the other hand, Transmission Owners who choose to be less proactive often would not identify such encroachments because the CCZ and encroachments of it are generally not easy to determine without taking precise measurements. Unless the line is heavily loaded or the vegetation is significantly overgrown, encroachments of the CCZ would not be readily noticed. In most cases these Transmission Owners would simply remove or cut back incompatible vegetation without taking measurements. The threat to the line would have been eliminated with no encroachment having been identified.R4 presents a dilemma for Transmission Owners that are considering making the significant investment in ALS technology. While the technology would allow them to identify any potential grow-in or fall-in conditions, it would also expose them to the risk of identifying violations of R4, that would otherwise not have been identified. Violation Risk Factors (VRFs), Violation Severity Levels (VSLs), and Time Horizons are not included in this Draft, but after making a significant investment in ALS, Transmission Owners could be faced with significant additional cost in terms of NERC penalties. In addition, even if the penalties were relatively low they would be exposing themselves to violations that less proactive Transmission Owners would not be exposed to. In our view R4 as written would, in some cases, have the opposite effect of what is intended because the business case for using ALS is more difficult to make. This will result in less use of ALS and other emerging technology that is likely to be developed. This would result in fewer problems being identified, a small percentage of which will not be discovered until they result in a line trip. Still we believe that the concept of the CCZ is a good one and recommend that R4 be changed so that Transmission Owners are provided with an incentive to invest in the best technology available in order to ensure the highest level of reliability. The opportunity exists to develop the standard in a manner that encourages the industry to take advantage of new technology and manage vegetation in a very proactive way. We recommend that R4 be changed as follows: Modify R4 to require Transmission Owners to immediately implement the imminent threat process defined in R1.4 when they identify instances where the CCZ is approached or encroached upon. Failure to do so would be a violation of R4. Eliminate encroachment of the CCZ as a violation of R4. This would eliminate R2 and incorporate implementation of the imminent threat process into R4.Require Transmission Owners to report to the Regional Entity on a quarterly basis any instances where the imminent threat process was implemented due to an encroachment of the CCZ. This would add a reporting requirement for Transmission Operators. Require Transmission Owners to report to the Regional Entity on a quarterly basis any instances where either a momentary or sustained outage was caused by grow-ins, Active Transmission Line Right of Way blow-ins, or Active Transmission Line Right-of-Way fall-ins. This would add three additional reporting requirements for Transmission Operators. Require Regional Entities to perform additional audits of Transmission Owners that exceed metrics for violations of the CCZ. The metrics would be established in this Standard based upon 100 circuit miles of applicable lines. This would add an additional requirement for Regional Entities. This concept would result in a more rigorous standard than FAC-003-01 because of the additional reporting and auditing requirements. It would drive proactive behavior throughout the industry and provide a significant incentive for Transmisison Owners to invest in new technology such as ALS that is capable of accurately identifying vegetation that has approached or encroached upon the CCZ. We believe that this change would result in the identification of more incipient vegetation-related problems and fewer vegetation-related outages as soon as it was implemented and

Organization	Agree?	Question 15 Comment
		would best support the purpose of the Standard.
Response: The SDT thanks you for your comments and suggestions. The reporting and documenting concept that you suggest has been incorporated in part in R2. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Buckeye Power, Inc.	Disagree	Proving vegetation is not in a clearance zone will be difficult without having third-party verification.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Great River Energy	Disagree	GRE supports the elimination of R4, as vegetation contacts are covered in R5 and R6. A violation should only occur with a vegetation contact. Assessing a violation and fine for a potential reduction in system reliability is not correct. Actual contacts that trip a transmission element have some measurable impact on system reliability even if it is slight. In the event that the SDT chooses not to eliminate R4, GRE would also support the alternative language that is shown under the second bullet.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
WECC	Agree	Yes, R4 as written provides clear guidance to TOs on the minimum radial distance, dependant on line voltage that vegetation is allowed to approach energized conductors. These industry standardized distances will ensure a level of reliability equal to or better than FAC-003-1.
Response: The SDT thanks for your comments. Please see the summary consideration for this question – based on other comments, the SDT made significant revisions to Requirement R4. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
National Grid	Agree	National Grid agrees that there should be no encroachments into the CCZ. However, encroachments in the CCZ should NOT be considered a violation. Violations should only be for sustained transmission outages.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and		

Organization	Agree?	Question 15 Comment
Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Northern California Power Agency (NCPA)	Agree	
WECC Reliability Coordination	Agree	
Response: The SDT thanks you for your positive feedback. Most commenters disagreed with R4. Changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		

16. Requirements R5, R6, and R7 define that Sustained Outages due to vegetation growing into, blowing together with, and falling into transmission lines are violations (subject to certain exemptions). Therefore, all such outages must be reported as violations of the standard. Do you agree with this change? If not, please explain.

Summary Consideration: Seventy two percent of the respondents agreed with the changes. Multiple commenters made the following points: Questionable cost benefit, not all lines are equal, complicated and burdensome to know precisely where edge of ROW is, the standard should read minimize outages and not prevent them. The majority of the team did not agree there was sufficient argument to support making changes to the requirements based on the comments.

Several commenters pointed out that debris that has been detached from the tree and blown into the conductor and trees from outside the ROW should be exempt. The team adjusted the standard to accommodate debris and falling from outside the ROW.

Organization	Agree?	Question 16 Comment
Western Utility Arborists		The Western Utilities strongly recommend that the requirement under R7 be changed from “shall prevent sustained outages” to “shall minimize sustained outages due to vegetation falling into a conductor.” We note that the word “minimize” was present in earlier drafts of the document. We are concerned about the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. This could lead to an incident where utilities are charged unreasonably? for example, for an outage from a tree that was one foot within the active ROW line. We should not be held liable when reasonable due diligence is practiced. Further, it is not economically feasible for utilities to survey every ROW in the U.S. and Canada to determine precise clearance zones.
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT. The SDT believes that the Transmission Owner holds responsibility for knowing the location of the edges of its active rights of way and whether a rooted tree is within or outside the active right of way.		
BCTC		BCTC strongly recommends that the requirement under R7 be changed from “shall prevent sustained outages” to “shall minimize sustained outages due to vegetation falling into a conductor.” We note that the

Organization	Agree?	Question 16 Comment
		word “minimize” was present in earlier drafts of the document. BCTC is concerned about the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW BCTC’s operating area covers rugged and remote terrain, and many areas have accessibility issues. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. Further, it is not economically feasible to accurately survey and marked on the ground the absolute width of all ROW in the province. Therefore, we are concerned about the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW. This could lead to an incident where BCTC is charged unreasonably – for example, for an outage from a tree that was one foot within the active ROW line. We should not be held liable when reasonable due diligence is practiced.
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT. The SDT believes that the Transmission Owner holds responsibility for knowing the location of the edges of its active rights of way and whether a rooted tree is within or outside the active right of way.		
Kansas City Power & Light	Disagree	Exceptions should include flying debris including vegetation.
Response: Thank you for your comment. Your suggestion has been incorporated.		
Associated Electric Cooperative Inc.	Disagree	Requirements 5, 6 and 7, as written, compel the Transmission Owner to allocate precious resources to ensuring a vegetation related outage will NEVER occur on any applicable transmission line, regardless of the line's true importance to maintaining electric transmission system reliability. All lines are not created equal; only those which are an IROL or contribute to IROLs should be held to a zero tolerance standard.
Response: Thank you for your comments. FERC Order 693 affirmed that the Standard shall apply to all transmission lines operating above 200kV as well as to designated sub-200kV lines. The Standard was prepared in accordance with FERC Order 693.		
NPCC	Disagree	NPCC participating members request clarification if violations of R5, R6, and R7 result in outages that must be reported.
Response: The SDT appreciates your response. Under NERC’s Compliance Guidelines, any violation of a reliability standard requirement must be self-reported; thus, a violation of Requirement R5, R6 or R7 must result in a report from the Transmission Owner.		
SERC OC Standards Review	Disagree	R5, R6 and R7 should begin with "Subject to its legal rights,”. The requirements, as written, compel the Transmission Operator to allocate precious resources to ensuring that a vegetation outage NEVER will occur

Organization	Agree?	Question 16 Comment
Group		on any transmission line, regardless of that line's true importance to maintaining electric transmission system reliability. All lines are not created equal; only those that are involved in IROLs should be held to a zero tolerance standard. R5, R6, and R7 ensure that version 2 of the standard has reliability requirements equal to version 1; therefore R4 should be removed.
Response: Thank you for your comments. **The SDT certainly agrees that all actions taken by a Transmission Owner must be within its legal rights, but believes that inclusion of "*Subject to its legal rights*" will tend to unnecessarily limit legitimate actions that a Transmission Owner must take to maintain reliability.** **FERC Order 693 affirmed that the Standard shall apply to all transmission lines operating above 200kV as well as to designated sub-200kV lines. The Standard was prepared in consideration of the directives and recommendations contained in FERC Order 693.**		
Florida Power & Light	Disagree	As currently written, Requirements R5, R6 and R7 demand perfection. The only acceptable number for all 150K miles of affected transmission line in the US is 0. The standard should be achievable and enable proactively addressing potential threats to facilities from vegetation. Even using a Six Sigma level of quality and control, processes can achieve a level of 3.4 defects per million opportunities for defect. Each tree on the ROW represents one of those opportunities. FPL has outlined an alternative proposal in response to Question 18.
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT.		
Santee Cooper	Disagree	Recommend removing R7 because current and proposed standards do not require the entire right-of-way or Active Transmission Line Right of Way to be clear of vegetation. In this case, a utility should not be penalized if a tree falls from within the right-of-way or Active Transmission Right-of-Way as long they are meeting all the other standards (e.g., minimum vegetation clearance distances). Since fall-ins from just outside of the right-of-way is currently not a compliance issue, it makes sense that a fall-in from within the right-of-way be treated the same. This is especially true for a utility who has elected to acquire a wider right-of-way than another utility. That utility may have a tree(s) growing just inside the right-of-way but still maintains a better clearance distance between trees and conductors than a utility with a narrower right-of-way and no tree encroachment.
Response: Thank you for your comments. While it is true that there is a negligible difference in risk to the electric system for trees just within or just outside the active right of way, the major difference is that the Transmission Owner generally has the right to manage vegetation within the active right of way. Also, while Transmission Owners employ differing active right-of-way widths, this is essentially uncontrollable by the SDT or by regulators.		

Organization	Agree?	Question 16 Comment
Exelon	Disagree	It appears to Exelon that the requirements of the standard have been written and modified at different times and as a result the document lacks a degree of consistency and coherence. While the Standard mentions encroachment of the CCZ and Sustained Outages as potential violations, it is completely silent on how momentary outages should be addressed. Exelon views the following events as a risk continuum that should be addressed in the Standard and handled as a part of the VRFs and VSLs - encroachment of the air gap distance, momentary outages and Sustained Outages.
Response: Thank you for your comments. The Minimum Vegetation Clearance Distance is the calculated spark-over distance derived from the Gallet equations. Therefore a momentary caused by a tree under the circumstances defined in R4 would by definition be a violation of R4.		
Platte River Power Authority	Disagree	The requirement under R7 should be changed from "shall prevent sustained outages" to "shall minimize sustained outages due to vegetation falling into a conductor." We note the word "minimize" was present in earlier drafts of the document. We are concerned about the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. This could lead to an incident where utilities are charged unreasonably - for example, for an outage from a tree that was one foot within the active ROW line. We should not be held liable when reasonable due diligence is practiced.
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT. The SDT believes that the Transmission Owner holds responsibility for knowing the location of the edges of its active rights of way and whether a rooted tree is within or outside the active right of way.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Disagree	I believe that the text for each element should be re-written with the general philosophy that the Transmission Owner shall do everything reasonable to prevent such problems in line with the comment for section 15.Problems should be reported and investigated and a judgment call should be made about whether the Transmission Owner did everything reasonable to avoid the problem.
Response: Thank you for your comments. The purpose of this standard is to improve reliability of the electric transmission system by preventing vegetation-related outages that can lead to cascading by establishing clear and measureable requirements. While the SDT appreciates the value of judgment in the field FERC has indicated that requirements in proposed Standards be equivalent to or more stringent than the same or similar requirements in already approved Standards.		
Consumers Energy Company	Disagree	R5, R6 and R7 should be rewritten as a single requirement for vegetation within the "Active Transmission Line Right of Way" and the exceptions listed. Additionally, a requirement for hazardous trees outside of the "Active

Organization	Agree?	Question 16 Comment
		Transmission Line Right of Way" should be incorporated into this draft and similar exceptions listed for natural disasters, third-party, and animal causes.
Response: Thank you for your comments. Requirements R5, R6 and R7 deal with three distinct types of outages which may pose different risks or severity in terms of impact to the electric system. The SDT chose to break the three requirements apart to allow application of different Violation Risk Factors because blow-in and fall-in interruptions do pose a significantly lower risk of causing a cascading blackout event. **Regarding incorporating a requirement to address hazardous trees outside the Active Right-of-Way, Transmission Owners generally have the right to manage vegetation within the Active Transmission Right-of- Way. These rights will not always exist beyond the Active Transmission Right-of-Way.**		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Disagree	We strongly recommend that the requirement under R7 be changed from “shall prevent sustained outages” to “shall minimize sustained outages due to vegetation falling into a conductor.” We note that the word “minimize” was present in earlier drafts of the document. We are concerned about the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. This could lead to an incident where utilities are charged unreasonably ? for example, for an outage from a tree that was one foot within the active ROW line. We should not be held liable when reasonable due diligence is practiced. Further, it is not economically feasible for utilities to survey every ROW in the U.S. and Canada to determine and document precise clearance zones. Such costly effort would not produce any benefit to the reliability of the bulk electric system.
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT. The SDT believes that the Transmission Owner holds responsibility for knowing the location of the edges of its active rights of way and whether a rooted tree is within or outside the active right of way.		
San Diego Gas & Electric	Disagree	We recommend that the requirement under R7 be changed from "shall prevent sustained outages" to "shall minimize sustained outages due to vegetation falling into a conductor." The word minimize was present in earlier drafts of the document. We are concerned with the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission Right of Way. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. This could lead to an incident where utilities are charged unreasonably.
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT. The SDT believes that the Transmission Owner holds responsibility for knowing the location of the edges of its active rights of way and whether a rooted tree is within or outside the active right of way.		

Organization	Agree?	Question 16 Comment
Hydro One Networks Inc.	Disagree	A further exception would be a sustained outage where the conductor has moved outside of the critical clearance zone. This could occur under conditions of heavy icing, operating outside the line rating or excessive wind. These would not necessarily be the result of a natural disaster. Also, it is recommended that the requirement for R7 be revised to “Each Transmission Owner shall minimize (“minimize” replacing “prevent”) Sustained Outages of applicable lines due to vegetation falling into a conductor”.. A fall in is a random occurrence and the likelihood that this would be the cause or contribute to a cascading event is very remote. These types of outages are rare and can be considered similar in nature to an insulator flashover or a hardware failure, which have not been given any association with cascading events. The purpose of the standard is to prevent cascading events and it is suggested that this remain the focus and not introduce other types of outages on a selective basis.
Response: Thank you for your comment. The Critical Clearance Zone (CCZ) has been removed from the standard. **The SDT concurs that fall in events present a lower risk to the system than grow in events. Requirements R5, R6 and R7 have been drafted to address three distinct types of outages which may pose different risks or severity in terms of impact to the electric system. The SDT chose to break the three requirements apart to allow application of different Violation Risk Factors and Violation Severity Levels.**		
Arizona Public Service Company	Disagree	APS strongly recommends that the requirement under R7 be changed from “shall prevent sustained outages” to “shall minimize sustained outages due to vegetation falling into a conductor.” We note that the word “minimize” was present in earlier drafts of the document. We are concerned about the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. This could lead to an incident where utilities are charged unreasonably ? for example, for an outage from a tree that was one foot within the active ROW line. We should not be held liable when reasonable due diligence is practiced. Further, it is not economically feasible for utilities to survey every ROW in the U.S. and Canada to determine precise clearance zones.
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT. The SDT believes that the Transmission Owner holds responsibility for knowing the location of the edges of its active rights of way and whether a rooted tree is within or outside the active right of way.		
Entergy Services	Disagree	1. If a version of R4 that states an encroachment to the Critical Clearance Zone is a violation, Entergy disagrees with the need for R5, R6, and R7 because it is redundant to R4. An outage cause by vegetation: a) growing into the line b) blowing into the line and c) falling into the conductor would require the vegetation to break the Critical Clearance Zone. If these requirements stay in the standard, an outage of the above nature would mean the entity violated two requirements, R4 and R5, R6, or R7. 2. Entergy is amenable to keeping

Organization	Agree?	Question 16 Comment
		R5, 6, and 7 if R4 is removed from the standard. 3. If approved, we suggest that R5, 6, and 7 not apply to trees from off the right of way.
Response: Thank you for your comments. Requirements R5, R6 and R7 have been drafted to address three distinct types of outages which may pose different risks or severity in terms of impact to the electric system. The SDT chose to break the requirements apart to allow application of different Violation Risk Factors and Violation Severity Levels. R4 has been drafted to clarify that clearance encroachments are violations of the Standard. Matters of being assessed two violations for a single event are addressed in the NERC compliance sanctions guideline.		
Salt River Project	Disagree	Recommend that the requirement under R7 be changed from "shall prevent sustained outages" to "shall minimize sustained outages due to vegetation falling into a conductor". We understand that the word "minimize" was present in earlier drafts of the document. We are concerned about the requirement to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. This could lead to an incident where a utility is charged unreasonably - for example, for an outage from a tree that was one foot within the active ROW line. We should not be held liable when reasonable due diligence is practiced. Furthermore, it is not economically feasible for utilities to survey every ROW to determine precise clearance zones.
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT. The SDT believes that the Transmission Owner holds responsibility for knowing the location of the edges of its active rights of way and whether a rooted tree is within or outside the active right of way.		
Hydro-Quebec Transenergie (HQT)	Disagree	HQT request clarification if violations of R5, R6, and R7 result in outages that must be reported. A further exception would be a sustained outage where the conductor has moved outside the critical clearance zone. This could occur under conditions of heavy icing, operating outside the line rating or excessive wind.
Response: Thank you for your comments. Regarding your question on reporting of violations, under NERC's Compliance Guidelines, any violation of a reliability standard requirement must be self-reported; thus, a violation of Requirement R5, R6 or R7 must result in a report from the Transmission Owner. In addition, the revised standard includes compliance elements, including the need to provide periodic reports of specific vegetation-related outages. **The Critical Clearance Zone (CCZ) is defined by the movement of the conductor between no load and its rating. The Standard does not apply to events which occur outside of the CCZ.**		
Southern California Edison	Agree	Q16: SCE agrees in part with the establishment of R5, R6 and R7, however, we note that the opening of each requirement repeats a slightly altered version of the FAC-002-2 purpose statement. We find such

Organization	Agree?	Question 16 Comment
Company		repetitiveness unnecessary and note that as written, Requirements 5-7 presents a near identical compliance conundrum for Transmission Owners as Requirement 4. Again, Transmission Owners would be required to prove that they did not incur a sustained outage due to a vegetation caused flash-over or vegetation-to-line contact whether it be a grow-in, blow-in or fall-in. Although proving a sustained outage (for cause) did not occur will be difficult and unwieldy, it is not impossible. The simple difference between a Transmission Owner disproving the occurrence of a CCZ incursion and their disproving vegetation caused sustained outages, is that Transmission Owners do in fact keep records of “outages”. Because a Transmission Owner’s record keeping prowess is the only viable option for proving a vegetation caused outage did not occur, SCE respectfully suggests R5, R6 and R7 be revised to read:R5 - "Each Transmission Owner shall document Sustained Outages of applicable lines due to vegetation growing into a conductor operating within its Rating with the following exceptions:"R6 - "Each Transmission Owner shall document Sustained Outages of applicable lines due to vegetation blowing into a conductor operating within its Rating and located within an Active Transmission Line Right of Way with the following exceptions:"R7 - "Each Transmission Owner shall document Sustained Outages of applicable lines due to vegetation falling into a conductor operating within its Rating and located within an Active Transmission Line Right of Way with the following exceptions: "We also note that Footnote 6 is misplaced in the draft and should follow the word “Outages” in each of these requirements.
Response: Thank you for your comments. Requirements R5, R6 and R7 deal with three distinct types of outages which may pose different risks or severity in terms of impact to the electric system. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Additionally, the Transmission Owner must document and report outages under NERC’s Compliance Guidelines. However, the SDT chose to break the three requirements apart to allow application of different Violation Risk Factors and Violation Severity Levels. **As to the matter of proving the lack of CCZ incursions, please refer to the SDT’s response to your Question # 15 comments.** **Your suggestion regarding Footnote 6 has been incorporated.**		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 16.
Response: Thank you for your comments.		
American Electric Power (AEP)	Agree	AEP is in agreement with these changes.
Response: Thank you for your supportive comment.		
City of Tallahassee	Agree	Why have we gone backwards with only "Sustained Outages" being a violation? Even a momentary outage indicates that a violation has occurred if the cause was vegetation related (with the same exceptions). This

Organization	Agree?	Question 16 Comment
		would seem to contradict the proposed R4. If it wasn't a Sustained Outage it wasn't a violation? If you have a sustained outage due to vegetation, you must have violated the CCZ.
Response: Thank you for your comments. The SDT very carefully and thoroughly examined the merits, disadvantages, ease and difficulties of assessing momentary outages as a violation. The result of that effort led to the more precise and field observable aspects of R4. It should be noted that by their very nature the exact causes of "momentary outages" are very challenging to determine and will vary widely from utility to utility. The SDT did not find that such variability was appropriate for a reliability standard, and chose to address this issue with the language in R4.		
Northern Indiana Public Service Company	Agree	While being more specific & explicit, I don't interpret the overall requirement as being any different from the current standard.
Response: Thank you for your comment. Please note that while the current standard did not specifically define an interruption as a violation, the proposed standard explicitly defines outages as violations.		
Orange and Rockland Utilities Inc.	Agree	We agree, but recommend that momentary outages be included as violations of all three requirements as well. Also, the Standard does not directly require reporting of vegetation-related outages although implicitly, outages which are violations of the Standard must be reported. This has lead to some confusion during this comment phase and we suggest that the reporting requirements be directly stated in the Standard.
Response: Thank you for your comments. Under the Compliance section of the new standard section 2 the Transmission Owner is required to report outages.		
Xcel Energy	Agree	We agree, however please add a reference to ?wind gusts 45 miles per hour or greater? to the exception note for this requirement. The exception would read ?1) Sustained Outages of transmission lines that result from sustained winds (45 miles per hour or greater) or gusts due to natural disasters.?
Response: Thank you for your comments. The SDT believes that a fresh gale (see footnote 4) represents an appropriate threshold for exemptions.		
Manitoba Hydro	Agree	Agree with splitting the various events. We note that there is no specific requirement to actually report an outage. The Requirements say that we should Prevent Sustained Outages, but not actually report sustained outages should they occur. In version 1, R3 clearly stated that the Transmission Owner shall report.
Response: Thank you for your comments. Under NERC's Compliance Guidelines, any violation of a reliability standard requirement must be self-reported; thus, a violation of Requirement R5, R6 or R7 must result in a report from the Transmission Owner.		

Organization	Agree?	Question 16 Comment
National Grid	Agree	National Grid agrees with the proposed change, however, Standard FAC-003-2 does not provide outage reporting requirements in R5, R6, R7, or anywhere else in the Standard.
Response: Thank you for your comments. Under NERC's Compliance Guidelines, any violation of a reliability standard requirement must be self-reported; thus, a violation of Requirement R5, R6 or R7 must result in a report from the Transmission Owner. The revised standard includes compliance elements, including the need to provide periodic reports of specific vegetation-related outages.		
Pacific Gas & Electric Co.	Agree	M5, M6 and M7 do not explicitly exclude the exceptions in R5, R6 and R7 and should do so.
Response: Thank you for your comments. The SDT believes that the requirements and measures are properly aligned. The exceptions language is appropriately located in the technical requirement.		
Consolidated Edison Company of New York (CECONY)	Agree	CECONY agrees that outages caused by the factors mentioned are violations of R5, R6, and R7 but we recommend that either the phrase 'momentary outage' be included in the wording or the phrase 'All Outages' replace 'Sustained Outages' to make the requirements clearer.
Response: Thank you for your comments. The SDT very carefully and thoroughly examined the merits, disadvantages, ease and difficulties of assessing momentary outages as a violation. The result of that effort led to the more precise and field observable aspects of R4. It should be noted that by their very nature the exact causes of "momentary outages" are very challenging to determine and will vary widely from utility to utility. The SDT did not find that such variability was appropriate for a reliability standard, and chose to address this issue with the language in R4.		
WECC	Agree	However reporting requirements are not identified in the standard. WECC believes that sustained outages caused by vegetation should be reported to the Regional Entity using the existing reporting requirements in FAC-003-1
Response: Thank you for your comments. Under NERC's Compliance Guidelines, any violation of a reliability standard requirement must be self-reported; thus, a violation of Requirement R5, R6 or R7 must result in a report from the Transmission Owner. The revised standard includes compliance elements, including the need to provide periodic reports of specific vegetation-related outages.		
CenterPoint Energy	Agree	We agree with the exemptions; however, R6 and R7 refer to an "Active Transmission Line Right-of-way" which is not defined as to its limits, so M6 and M7 cannot be determined by definition. See comments to Q3 above relating to the definitions and the examples in the Technical Reference.
Response: Thank you for your comments. The SDT asserts that the Transmission Owner is responsible for defining the Active Transmission Line Right of Way. Additionally please refer to the response to Question 3. Note that the SDT made significant changes to clarify R5, R6 and R7 and the associated		

Organization	Agree?	Question 16 Comment
measures.		
Pepco Holdings, Inc	Agree	There is no need for three separate requirements if the incident is a Sustained Outage, but there is nothing inherently wrong with the three requirements.
Response: Thank you for your comments. Requirements R5, R6 and R7 have been drafted to address three distinct types of outages which may pose different risks or severity in terms of impact to the electric system. The SDT chose to break the requirements apart to allow application of different Violation Risk Factors and Violation Severity Levels.		
Northeast Utilities	Agree	Agree that contacts resulting in sustained outages due to vegetation from within the active transmission line right-of-way should constitute a violation of the Standard. However, this Standard is written for a zero tolerance of any vegetation caused outages or encroachment into the CCZ. One vegetation-caused outage or one CCZ encroachment may not result in a potential Cascading effect. Agree with the use of different violation risk factors (VRF's) and violation severity levels (VSL's) for each of the three outage classes. Also - how are outage violations to be reported - there is no provision in the revision for the reporting process and requirements (specifics on the type of violation). Will this be addressed in the Compliance Section yet to be added? Suggest in both R6 and R7, move the phrase "within an Active Transmission Line Right of Way" to immediately follow "vegetation".
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT. **Requirements R5, R6 and R7 have been drafted to address three distinct types of outages which may pose different risks or severity in terms of impact to the electric system. The SDT chose to break the requirements apart to allow application of different Violation Risk Factors and Violation Severity Levels.** **Regarding your question on reporting of violations, under NERC's Compliance Guidelines, any violation of a reliability standard requirement must be self-reported; thus, a violation of Requirement R5, R6 or R7 must result in a report from the Transmission Owner. In addition, the revised standard includes compliance elements, including the need to provide periodic reports of specific vegetation-related outages.** **Your suggested wording change to requirements R6 and R7 was evaluated by the SDT. The SDT asserts that the original wording is appropriate.**		
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	

Organization	Agree?	Question 16 Comment
Northern California Power Agency (NCPA)	Agree	
Central Maine Power Company	Agree	
Tampa Electric Company	Agree	
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
SERC Vegetation Management Subcommittee (VMS)	Agree	
Progress Energy Florida	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Progress Energy Carolinas	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
Bonneville Power Administration	Agree	
FirstEnergy	Agree	
MRO NERC Standards Review Subcommittee	Agree	

Organization	Agree?	Question 16 Comment
Midwest ISO Stakeholders Standards Collaborators	Agree	
Ameren	Agree	
American Transmission Company	Agree	
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Edison Electric Institute	Agree	
Baltimore Gas & Electric Company	Agree	
Duke Energy Corporation	Agree	
JEA	Agree	
Independent Electricity System Operator	Agree	
Buckeye Power, Inc.	Agree	
Great River Energy	Agree	

17. R8 is a new requirement which separates the implementation of the annual plan from the requirement to have an annual plan. Do you agree with R8? If not please explain.

Summary Consideration: The SDT modified the Requirement for implementation of the work plan (now R9 in the revised standard) after reviewing these comments. Commenters focused on two main areas. First, there was a suggestion that the work plan wording be amended to include a note that it was only required on the Active Right of Way. Requirement R1 clearly limits the scope of the TVMP to work on the entity's Active Transmission Line Rights of Way - and the "annual work plan" is one element of the overall TVMP. The second overriding theme was that the standard be re-ordered to better tie the requirement to have a plan and the requirement to implement a plan. Some commenters suggested that the requirement to implement the annual work plan be embedded as part of Requirement R1, and the SDT did not make this change. The requirement to "have" a TVMP is administrative and the requirement to "implement" the annual work plan is a real-time requirement – by keeping these requirements separate, each requirement can be assigned an appropriate VRF. The SDT is offering for comment a proposed re-ordering of the Standard that provides a more logical sequence to the Standard which, if supported by stakeholders, can be applied to Draft 3 of the standard.

For Draft 2, the SDT also removed the wording "within the extent of its easements and/or legal rights." The justification for removing these words was to remove the possibility that the TO would be held to the maximum criteria or be limited to the minimum criteria outlined in their easements.

R9. Each Transmission Owner shall implement its annual work plan for vegetation management to accomplish the purpose of this standard.

Deleted: R8

Deleted: within the extent of its easement and/or legal rights

Organization	Agree?	Question 17 Comment
Central Maine Power Company		Central Maine Power Company suggests that R9 read as A Transmission Owner shall implement its annual work plan within the Active Right of Way to the the extent of its easements or legal rights.
Response: The SDT thanks you for your response. In response to overwhelming industry comments The SDT has removed the words "within the extent of its easements and/or legal rights". The SDT also feels that the Active Right of Way concept is supported adequately in Requirement R1 which limits the scope of the TVMP (and the annual work plan) to the entity's Active Rights of Way.		
British Columbia Transmission Corp		BCTC understands that it's possible to have an annual plan and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the plan is kept together with the requirement to implement it.
Response: The SDT thanks you for your response. The SDT proposes a new sequence for the technical Requirements R1-R11 and seeks industry feedback as requested in Question 4 of the Second Comment Form.		

Organization	Agree?	Question 17 Comment
Western Utility Arborists		The Western Utilities understands that it's possible to have an annual plan and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the plan is kept together with the requirement to implement it.
Response: The SDT thanks you for your response. The SDT proposes a new sequence for the technical Requirements R1-R11 and seeks industry feedback as requested in Question 4 of the Second Comment Form.		
SERC Vegetation Management Subcommittee (VMS)	Disagree	While the SERC VMS agrees in principle, we believe that the Requirement, as written, is "open ended" and could be interpreted to be in conflict with the "Active Rights of Way" concept. Clarifying the intent for the annual plan to focus on the Active Rights of Way will prevent incorrect interpretations. The SERC VMS suggest that the Requirement be reworded to read: ?Each Transmission Owner shall implement its annual work plan for vegetation management within the Active Right of Way to accomplish the purpose of this standard within the extent of its easements and or legal rights.?
Response: The SDT thanks you for your response. The SDT considered your request at length but feels that the Active Right of Way concept is supported adequately in Requirement R1 which limits the scope of the TVMP (and the annual work plan) to the entity's Active Rights of Way.		
JEA	Disagree	See comment from #3.
Response: Thank you for your comment. Please see the response to comments on #3. .		
Salt River Project	Disagree	The document would be easier to follow if the two elements would be kept together in the same requirement (similar to comments in #4, #6, & #14 above). It makes the standard longer than necessary and creates redundancy.
Response: The SDT thanks you for your response. The reason that the development of the annual plan and the implementation of the plan were separated was to apply the appropriate VRF's and VSL's to each. The SDT feels that the current organization is appropriate because development of the annual work plan is a sub-part of the development of the Transmission Vegetation Management Program and should be separate from the implementation requirement for the annual plan.		
SERC OC Standards Review Group	Disagree	The SERC OCSRG suggests that the Requirement be reworded to read: "Each Transmission Owner shall implement its annual work plan for vegetation management within the Active Rights of Way." Any further verbiage is confusing, ambiguous or unnecessary.
Response: The SDT thanks you for your response. The SDT considered your request at length but feels that the Active Right of Way concept is supported adequately in the definition and elsewhere in the standard. The SDT did, however, remove the last phrase of the sentence, "within the extent		

Organization	Agree?	Question 17 Comment
of its easement and/or legal rights.”		
Florida Power & Light	Disagree	The standard goes to great length to specify the Active Transmission Right-of-Way but omits its reference in requirement R9. The inclusion of this term in Requirement R9 adds consistency to the application of the standard. FPL suggests the following change: "Each Transmission Owner shall implement its annual work plan for vegetation management to accomplish the purpose of this standard within the extent of its easement and/or legal rights in the Active Transmission Line Right-of-Way."
Response: The SDT thanks you for your response. Due to industry comments the SDT revised the wording on this requirement to delete the words “within the extent of its easements and/or legal rights”. The SDT also feels that the Active Right of Way concept is supported adequately in the Requirement R1 which limits the scope of the TVMP (and the annual work plan) to the entity’s Active Rights of Way.		
Southern Company	Disagree	While we agree in principle, we feel Requirement R9 as written is “open ended” and could be interpreted to be in conflict with the “Active Rights of Way” concept. Clarifying the intent for the annual plan to focus on the Active Rights of Way will prevent incorrect interpretations. We suggest that the Requirement be reworded to read: Each Transmission Owner shall implement its annual work plan for vegetation management within the Active Right of Way to accomplish the purpose of this standard within the extent of its easements and or legal rights.
Response: The SDT thanks you for your response. Due to industry comments the SDT revised the wording on this requirement to delete the words “within the extent of its easements and/or legal rights”. The SDT also feels that the Active Right of Way concept is supported adequately in Requirement R1 which limits the scope of the TVMP (and the annual work plan) to the entity’s Active Rights of Way.		
E.ON U.S.	Disagree	E.ON U.S. believes that the Requirement, as written, is “open ended” and could be interpreted to be in conflict with the "Active Rights of Way" concept. Clarifying the intent for the annual plan to focus on the Active Rights of Way will prevent incorrect interpretations. We suggest that the Requirement be reworded to read: “Each Transmission Owner shall implement its annual work plan for vegetation management within the Active Right of Way to accomplish the purpose of this standard within the extent of its easements and or legal rights.”
Response: The SDT thanks you for your response. The SDT agrees with your comments and has removed the words “within the extent of its easements and/or legal rights”. The SDT also feels that the Active Right of Way concept is supported adequately in Requirement R1 which limits the scope of the TVMP (and the annual work plan) to the entity’s Active Rights of Way.		
Exelon	Disagree	Strike "within the extent of it's easement and / or legal rights." This is unnecessary and will cause confusion. The annual work plan as required to be developed per R1.3 requires consideration of permitting, scheduling and regulatory limitations.

Organization	Agree?	Question 17 Comment
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support for your suggestion and the requirement has been revised to reflect your suggestion.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Disagree	We understand that it is possible to have an annual plan and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the plan is kept together with the requirement to implement it.
Response: The SDT thanks you for your response. The SDT feels that the current organization is appropriate because development of the annual work plan is a sub-part of the development of the Transmission Vegetation Management Program and should be separate from the implementation requirement for the annual plan. The SDT proposes a new sequence for the technical Requirements R1-R11 and seeks industry feedback as requested in Question 4 of the Second Comment Form.		
San Diego Gas & Electric	Disagree	We feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the plan is kept together with the requirement to implement the plan.
Response: The SDT thanks you for your response. The SDT feels that the current organization is appropriate because development of the annual work plan is a sub-part of the development of the Transmission Vegetation Management Program and should be separate from the implementation requirement for the annual plan. The SDT proposes a new sequence for the technical Requirements R1-R11 and seeks industry feedback as requested in Question 4 of the Second Comment Form.		
Baltimore Gas & Electric Company	Disagree	As in question no. 14 above for R1.2, it would seem to make more sense to combine R1.3 & R9 as follows: "Require development and implementation of an annual plan that?."
Response: The SDT thanks you for your response. The reason that the development of the annual plan and the implementation of the plan were separated was to apply the appropriate VRF's and VSL's to each. The SDT feels that the current organization is appropriate because development of the annual work plan is a sub-part of the development of the Transmission Vegetation Management Program and should be separate from the implementation requirement for the annual plan.		
Pepco Holdings, Inc	Disagree	THE SDT has introduced the term Active Transmission Line Right of Way. R9 should use this term to avoid any misinterpretation.
Response: The SDT thanks you for your response. In response to industry comments The SDT has removed the words "within the extent of its easements and/or legal rights". The SDT also feels that the Active Right of Way concept is supported adequately in Requirement R1 which limits the scope of the TVMP (and the annual work plan) to the entity's Active Rights of Way.		

Organization	Agree?	Question 17 Comment
Great River Energy	Disagree	GRE both Agrees and Disagrees. GRE agrees with the separation between having an annual plan and implementing it. However, GRE suggests removing all the words after vegetation management.
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support for your suggestion and the requirement has been revised to reflect your suggestion.		
City of Tallahassee	Disagree	Combined with Question 6. R9 needs to have the same flexibility that R1.3 has. As written, it could be argued that you have to do everything in your annual plan, AND anything in addition due to the changing conditions. This contradicts what is put forth in the white paper. I would add "as modified per R1.3" after "implement it's annual work plan for vegetation management"
Response: The SDT thanks you for your response. The SDT feels that the "flexibility" of the annual plan is built into the development of the plan and that same flexibility carries through to the implementation.		
Tampa Electric Company	Disagree	Good start. R9 must also address the flexibility which is addressed in R1.3. As written, R9 does not do this. In addition, R9 states "within the extent of its easement and/or legal right..". This could create another set of conflicting criteria, where the utility has a long term "interim corrective action plan".
Response: The SDT thanks you for your response. The SDT feels that the "flexibility" of the annual plan is built into the development of the plan and that same flexibility carries through to the implementation. The SDT does agree with the possible confusion the words "within the extent of its easement and/or legal rights" could cause and has consequently removed these words from the requirement.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Disagree	This standard needs to be broadened to include evaluation of the good faith efforts by the Transmission Owner to coordinate with the USFS on development of the work plan. A mechanism should be developed to allow the Transmission Owner to evaluate the good faith efforts of the USFS.
Response: The SDT thanks you for your response. The Standard is a continental reliability standard. While the SDT agrees with you that every Transmission Owner should strive for mutually beneficial relationships with the various landowners and other entities involved in vegetation management, it would be outside the purvey of this effort to outline specific relationships.		
Arizona Public Service Company	Disagree	APS understands that it's possible to have an annual plan and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the plan is kept together with the requirement to implement it.
Response: The SDT thanks you for your response. The SDT feels that the current organization is appropriate because development of the annual work plan is a sub-part of the development of the Transmission Vegetation Management Program and should be separate from the implementation		

Organization	Agree?	Question 17 Comment
requirement for the annual plan. The SDT proposes a new sequence for the technical Requirements R1-R11 and seeks industry feedback as requested in Question 4 of the Second Comment Form.		
SERC Compliance Staff	Agree	Vegetation management practices should be extended areas outside of the active rights-of-way (ROW) to the extent necessary to prevent vegetation-related outages. This should include the identification and removal of trees that could impact transmission line operation similar to the practice of identifying danger trees off of the ROW. The requirement as written could serve to reward those entities that, for whatever reason, have insufficient right-of-way widths. From a practical perspective, it should not be necessary to perform clear cutting of non-active ROW, but Entities should be held responsible for any outages that occur due to contact with vegetation within their legal rights to control.
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support to remove any wording referring to the easement rights. The SDT agreed with this view and has revised the requirement.		
ITC HOLDINGS	Agree	Clarifying the intent for the annual plan is to focus on the Active Rights of Way will prevent interpretation conflicts
Response: The SDT thanks you for your response. The SDT agrees with your observation, but also points out that the requirement for an annual work plan (sub-part 1.3) is part of Requirement R1, which specifically states its applicability to Active Transmission Line Rights of Way. Therefore, the SDT respectfully feels that your concern is addressed without additionally placing such verbiage in R8 (now R9).		
American Electric Power (AEP)	Agree	AEP agrees with this change.
Response: The SDT thanks you for your comments. The SDT modified the requirement, based on stakeholder comments, to remove the last phrase, "within the extent of its easement and/or legal rights."		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 17
Response: The SDT thanks you for your comment. The SDT modified the requirement, based on stakeholder comments, to remove the last phrase, "within the extent of its easement and/or legal rights."		
Platte River Power Authority	Agree	The separation allows lower sanctions and penalties to be assessed for a weak plan and higher sanctions and penalties to be assessed for not implementing an annual plan. However, we feel that the standard itself would be easier to follow if it was re-organized so that the requirement to have a plan is kept together with the requirement to implement it.

Organization	Agree?	Question 17 Comment
Response: The SDT thanks you for your response. The reason that the development of the annual plan and the implementation of the plan were separated was to apply the appropriate VRF's and VSL's to each. The SDT feels that the current organization is appropriate because development of the annual work plan is a sub-part of the development of the Transmission Vegetation Management Program and should be separate from the implementation requirement for the annual plan. The SDT proposes a new sequence for the technical Requirements R1-R11 and seeks industry feedback as requested in Question 4 of the Second Comment Form.		
American Transmission Company	Agree	ATC agrees with the requirement to implement the annual work plan, but recommends striking the words "within the extent of its easement and/or legal rights". The emphasis for this requirement is to execute the annual work plan. The white paper already speaks to the point that it is a best practice for utilities to exercise their legal rights. If we agree that the goal is to prevent outages, then we can simply end this requirement with "implement its annual work plan for vegetation management." Propose Changes to R9: Each Transmission Owner shall implement its annual work plan for vegetation management.
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support for your suggestion and the requirement has been revised to reflect your suggestion.		
Ameren	Agree	We recommend striking, or modifying, the words "within the extent of its easement and/or legal rights" as they may be introducing an unintended compliance quagmire. For example, if the easement is extraordinarily wide but reliability and the work plan do not dictate that the work plan apply to the entire easement, how will compliance be measured? The work plan should recognize easement or legal rights issue. Therefore, the emphasis for this requirement should be to execute the annual work plan. The white paper already speaks to the point that it is a best practice for utilities to exercise their legal rights. By tagging the words on to the requirement, we are adding unnecessary compliance validation to this requirement for both industry and the regulators. If a clarifying sentence is required, we would suggest that R9 stop with the word standard and a new sentence be added, "The work plan should address easement or legal/rights"
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support for your suggestion and the requirement has been revised to reflect your suggestion.		
MRO NERC Standards Review Subcommittee	Agree	The MRO both Agrees and Disagrees. The MRO agrees with the separation between having an annual plan and implementing it. However, the MRO suggests removing all the words after vegetation management.
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support for your suggestion and the requirement has been revised to reflect your suggestion.		

Organization	Agree?	Question 17 Comment
Midwest ISO Stakeholders Standards Collaborators	Agree	We recommend striking the words "within the extent of its easement and/or legal rights". The emphasis for this requirement is to execute the annual work plan. The white paper already speaks to the point that it is a best practice for utilities to exercise their legal rights. By tagging the words on to the requirement, we are adding unnecessary compliance validation to this requirement for both industry and the regulators. By the way this is written, it could be interpreted different ways. If we agree that the goal is to prevent outages, then we can simply end this requirement with "accomplish the purpose of the standard". Each Transmission Owner would be accountable to manage compliance with this standard and public relations in their service area.
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support for your suggestion and the requirement has been revised to reflect your suggestion.		
Duke Energy Corporation	Agree	Duke agrees with the requirement to implement the annual work plan, but recommends striking the words "within the extent of its easement and/or legal rights". The emphasis for this requirement is to execute the annual work plan. The white paper already speaks to the point that it is a best practice for utilities to exercise their legal rights. If we agree that the goal is to prevent outages, then we can simply end this requirement with "accomplish the purpose of the standard". Each Transmission Owner will be accountable to manage compliance with this standard.
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support for your suggestion and the requirement has been revised to reflect your suggestion.		
CenterPoint Energy	Agree	R9 requires implementation of the annual work plan "within the extent of its [the Transmission Owner's] easement and/or legal rights." All measures and compliance should be determined on this basis as well. This concept should also be carried through the definitions for "Active Transmission Line Right-of-way" and "Critical Clearance Zone", or for any definition of clearances should the Standard continue to utilize such terms.
Response: The SDT thanks you for your response. In response to industry comments The SDT has removed the words “within the extent of its easements and/or legal rights”. The SDT also feels that the Active Right of Way concept is supported adequately in the definition and in Requirement R1 which limits the scope of the TVMP (and the annual work plan) to the entity’s Active Rights of Way.		
Progress Energy Florida	Agree	While Progress Energy agrees with the change, the term “annual plan” should be a defined term including threshold elements.
Response: The SDT thanks you for your response. The SDT feels that the annual plan is adequately defined between the descriptions in the Standard (sub section 1.3) and in the technical reference document.		

<table>
<tr><th>Organization</th><th>Agree?</th><th>Question 17 Comment</th></tr>
<tr><td>Southern California Edison Company</td><td>Agree</td><td>Q17: SCE agrees in part with the inclusion of R9, however, we believe R9 should be revised and renumbered to replace proposed R3. In SCE’s view, the act of implementing a Transmission VM program encompasses both inspection and maintenance activities. SCE respectfully suggests that proposed R9 be revised to read: "Each Transmission Owner shall implement and follow its Vegetation Management Program to the extent allowed by existing easement and/or legal rights."</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your response. The SDT separates the vegetation inspections from the annual work plan because of partly due to the fundamental importance of the inspection process, and partly because a key purpose of an inspection is to provide input to the formation of the annual work plan. The SDT also points out that the TVMP is comprises the overarching processes and standards for program management, while the annual plan is the specific annual activities to accomplish the goals set forth in the program. In addition, the SDT modified the requirement, based on many other stakeholder comments, to remove the last phrase, “within the extent of its easement and/or legal rights.”</td></tr>
<tr><td>FirstEnergy</td><td>Agree</td><td>FirstEnergy agrees with the intent of R9, but the standard should be clarified by removal of the word "easement". As written the standard is open to interpretation between "easement" and active right of way. It is important to have the term "legal rights" remain in the standard. The Transmission Owner should be held accountable to fully enforce the legal rights outlined in maintaining the active right of way. This will lead to a more reliable transmission system.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your response. Due to industry comments the SDT revised the wording on this requirement to delete the words “within the extent of its easements and/or legal rights”. While we agree and state in the technical reference document that clearing to the maximum extent is in most cases the best practice, there are particular situations where a clear cut policy would not be in the best interest of the Transmission Owner or the landowner. The SDT also feels that the Active Right of Way concept is supported adequately in Requirement R1 which limits the scope of the TVMP (and the annual work plan) to the entity’s Active Rights of Way.</td></tr>
<tr><td>Pacific Gas & Electric Co.</td><td>Agree</td><td>PG&E agrees with the requirement to implement the annual work plan, but recommends removing the language "within the extent of its easement and/or legal rights".</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support for your suggestion and the requirement has been revised to reflect your suggestion.</td></tr>
<tr><td>Entergy Services</td><td>Agree</td><td>Entergy would like to note that requirements R1.3 and R9 are administrative requirements that add marginal value to the reliability of the Transmission System. Since entities are required to have flexible annual plans, deviations from the annual plan only need to be documented and these requirements will be met. Entergy utilizes annual plans as a good practice but sees limited value with the inclusion in this standard.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your response. After reviewing the industry comments there was broad concern that the current wording could</td></tr>
</table>

Organization	Agree?	Question 17 Comment
cause confusion with the wording "within the extent of its easements and/or legal rights". Consequently the SDT agreed with this view and has revised the requirement to address these concerns. The SDT respectfully disagrees that sub section 1.3 and R9 are administrative requirements and only add marginal value to the reliability of the system. Requirement R8 (now R9) is a real-time requirement, not an administrative requirement.		
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Northern California Power Agency (NCPA)	Agree	
Northern Indiana Public Service Company	Agree	
Bonneville Power Administration	Agree	
Orange and Rockland Utilities Inc.	Agree	
Manitoba Hydro	Agree	
Consumers Energy Company	Agree	
National Grid	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Independent Electricity System	Agree	

Organization	Agree?	Question 17 Comment
Operator		
Northeast Utilities	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
Buckeye Power, Inc.	Agree	
Santee Cooper	Agree	
Associated Electric Cooperative Inc.	Agree	
NPCC	Agree	
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Progress Energy Carolinas	Agree	
Response: Thank you for your positive response. The SDT modified the requirement, based on many other stakeholder comments, to remove the last phrase, "within the extent of its easement and/or legal rights."		

18. If you have further suggestions for improving this standard or the technical reference document, please offer them.

Summary Consideration: The overall industry feedback provided to this question reiterated concerns expressed in previous comments above. Most were related to the Critical Clearance Zone and associated issues of measurability, enforceability and practicality.

Organization	Question 18 Comment
Associated Electric Cooperative Inc.	R10 and R11: Associated Electric Cooperative Inc does not believe the Reliability Coordinator (RC) is the appropriate entity to determine whether or not selected sub-200 kv transmission lines should be subject to this standard. The planning horizon for the RC is typically much shorter than the time needed to incorporate a sub-200 kv transmission line into a vegetation management program. Associated recommends Planning Coordinator be designated as the applicable functional entity and be substituted wherever Reliability Coordinator appears in the Standard. M1.4: The language in M1.4, requiring immediate communication of an imminent threat to the Transmission Operator, is inconsistent with the Applicability in Section A.4.1.1 which designates the Transmission Owner as the responsible entity. M4: The preparation and retention of inspection reports, imminent threat reports, quality assurance reports, etc. is appropriate. These reports would not, however, absolutely demonstrate the Transmission Owner had experienced no vegetation encroachments into the Critical Clearance Zone. A negative cannot be proven. M6 and M7: The Transmission Owner is again expected to demonstrate a negative to prove compliance. Section C: Associated Electric Cooperative Inc recognizes the Standard, as posted, is a first draft for comments and will likely be revised before submittal for ballot. However, the Compliance section should be posted for an adequate comment period prior to balloting.
Response: The SDT thanks you for your comments. **The drafting team has made significant changes to the draft standard in response to industry comments, including the replacement of RC with PC.** **R1.4 and M1.4 are changed and the inconsistency has been resolved.** **R4 and M4 are changed such that real time observations during inspections and patrols replace the previous condition of proving a negative. In addition, the revised standard does not use the concept of the Critical Clearance Zone.** **M6 and M7 have been changed so that the proof of a negative is not required.** **The SDT had developed compliance elements for the industry to review in the second comment period.**	
NPCC	NPCC requests that the Standard Drafting Team review the compliance and reporting requirements for consistency and adequacy.

<table>
<tr><th>Organization</th><th>Question 18 Comment</th></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments. The drafting team has made significant changes to the draft standard in response to industry comments. Compliance elements have been added to the second draft of the standard.</td></tr>
<tr><td>WECC Reliability Coordination</td><td>R10 Should a dispute arise, how are those disputes resolved. Who keeps the list.

R10 What is acceptable methodology given the lack of interpretation of unacceptable risk of instability(R 10.2) or cascading failures. There is no definition of the consequences if a sub 200kv line is left off the list for vegetation management, and caused a cascading outage or placed the grid at an unacceptable risk of instability.</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments The drafting team has made significant changes to the draft standard in response to industry comments.

The RC has been replaced with the PC in R9 and R10.

This standard requires the PC to prepare and keep the list. Requiring the list to be developed in consultation with the TO ensures that the list will be available to the TO for the purposes in this Standard. The revised language should eliminate any disputes as the PC is ultimately the responsible entity for developing the list.

R10 was revised and now uses terminology that replicates terms within the IROL definition in the NERC Glossary of Terms for reliability standards. The intent is for the PC to use the same methods that determine those lines which are elements of an IROL be used to determine sub 200kV lines which are applicable to this standard.

While the planning study or similar analysis as cited in M10 could contain errors, it is not the intent of this standard to determine the competency of the PC or the results of PC any PC's analysis.</td></tr>
<tr><td>Western Area Power Administration, Upper Great Plains Region</td><td>1) Proactive utilities are implementing policies that call for the removal of all vegetation that could grow into the Critical Clearance Zone . Such policies are not without resistance from landowners, environmental groups, etc. One of the arguments used by such groups is that NERC/FERC do not require removal of the trees. It would very helpful if this document included the practice of removing vegetation capable of encroaching within the Critical Clearance Zone as a reasonable or acceptable practice under this Standard.

2) We can foresee a possible public backlash if this Standard is adopted as written. We see many utilities needing rate increases to cover the additional costs of implementing and monitoring the more stringent requirements of this proposal. We also believe that the more stringent requirements will have no noticeable impact on reliability. So you'll have the public paying more and seeing no change in reliability and questioning why.</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum vegetation clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. The Standard Drafting team has found that this Standard can not establish any legal basis to require Transmission Owners to exercise rights that do no</td></tr>
</table>

Organization	Question 18 Comment
exist within their transmission line easements or permits.	
Progress Energy Florida	To avoid interpretation errors and provide clarity, the Applicability section for Facilities (4.2) of FAC-003 should include a statement that the standard only applies to vegetation within the Active Transmission Line Right of Way. For example, a fall-in from outside of the Active Transmission Line Right of Way that causes a sustained outage is not a violation of this standard. Any encroachment/outage initiated by vegetation falling from outside of the Active Transmission Line Right of Way should be excluded from violations. The Critical Clearance Zone concept is academically elegant, but when applied in the field, it presents significant implementation, interpretation and enforcement issues: the complexity of determining compliance could have the unintended negative consequences to reliability; removal of vegetation will likely be delayed because of the complexity and accuracy required to determine compliance prior to tree removal; certification that no violations have occurred will require lengthy and costly calculations and survey measurements; the standard refers to Ratings in the determination of line sags and Ratings is not a tightly defined term, PRC-023 requires relays to hold lines in beyond the line Ratings; how will PRC-023 requirements be factored into the Critical Clearance Zone concept. The Critical Clearance Zone concept introduces more complexity and ambiguity into the standard than it resolves. The drafting team needs to develop an alternative to the Critical Clearance Zone concept that is simple, easy to apply and clearly defines at what point a violation occurs. There are over 158,000 line miles of AC Transmission above 200kV in the United States, covering a Right of Way area potentially as large as 3,000 to 4,000 square miles (an area roughly equivalent to Rhode Island and Delaware combined). With billions of stems of managed vegetation, in and along the right of way, even six-sigma performance would result in a number of outages on a system this large. With countless VM processes and assessments that take place daily, it is unrealistic/unreasonable to expect zero-tolerance for random vegetation events (the transmission system is planned/operated to handle at least any single contingency).
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. **The exclusion you request for vegetation falling through the MVCD, regardless of its being form inside or outside the right-of-way, has been added.** **Due to the industry impact that arises from zero tolerance for vegetation-related sustained outages, the Drafting Team tried several approaches but could not find a mechanism in the standard development process to establish a non-zero threshold for outages that was acceptable to FERC staff, because Standard revisions may not lead to less emphasis on reliability.** **The PRC-023 Standard seeks to ensure that transmission protective relays are properly set such that they do not trip a transmission element unnecessarily. This FAC-003 Standard seeks to prevent vegetation related Sustained Outages by requiring Transmission Owners to maintain their Active Transmission Line Rights of Way to be sufficiently clear. These two Standards are not mutually exclusive nor conflict with each other.**	
Kansas City Power & Light	The title and explanation for Table 1 in Attachment 1 is not clear as to it's usage and applicability. It is being confused with the correlation with a minimum clearance and not as a component or building block of the Critical Clearance Zone. Under R10, there may be other methods for consideration of assessing reliability significance of the sub-200 kV lines other than what is

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<tr><th>Organization</th><th>Question 18 Comment</th></tr>
<tr><td></td><td>listed. Suggest the Drafting Team consider other criteria that an RC should consider in its processes.

R10.2 is redundant with R10.1. IROL by definition are those operating limits that represent instability, uncontrolled separation or cascading. Suggest removing R10.2.

Under M1.3 the measure requires the annual plan to cover a calendar year. An annual plan may cover a cycle growing season to growing season using the inspection to verify the next seasons work.

Suggest removing the language for calendar year.M5, M6, M7 The measures should be requesting the evidence that it has violated the requirements. Good standing programs should not have to defend good practice by providing useless reports. The FAC-003-1 existing requirement R4 for reporting sustained outages is a reasonable and sustainable method that should be retained.R10 should include a periodic review period of annually. Any requirement to maintain current documentation should have a review period.</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time.

Under M10 (now M11) the language now allows the criteria used in planning studies and analysis to be acceptable measures for R10 (now R11).

The redundancy in 10.1 and 10.2 you found has been removed.

The reference to the calendar year that was in M1.3 has been removed.

M5, M6, M7 language has been changed. These measures now rely on the certification reports to the RE reporting will occur for both full compliance and any violations. The revised standard includes data retention periods as well as more detailed compliance information.</td></tr>
<tr><td>Western Area Power Administration, Rocky Mountain Region</td><td>1. Further clarification of the definition of the active right-of-way appears to be required. For example, if a tree falls from an area controlled by the utility which is outside of the normal width of the actively managed right-of-way, but this area is not reserved or "intended for other facilities", could this be a violation of a Standards requirement? The narrative discussion within the white paper seems to imply that it is not, but the "intended for other facilities" requirement within Standards definition implies that it would be.

2. As currently presented, FAC-003-2 requires an impractical and unrealistic level of performance from the industry. This level of performance is unwarranted for the overwhelming number and expanse of transmission facilities to which the Standards are applicable. Many of these facilities, such as radial load lines, are not critical Transmission OwnerT or IROL facilities and have a minimal impact on overall grid reliability. The rigorous zero tolerance level of performance is only warranted for those lines that are critical Transmission OwnerT or IROL facilities.

3. The Standards should clearly identify any and all reporting requirements.</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments.

1. The definition of the Active Transmission Line Right of Way states it is “A strip of land that is occupied by active transmission facilities. This corridor</td></tr>
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Organization	Question 18 Comment
does not include the inactive Right of Way or unused part of the Right of Way intended for other facilities." This definition is not limited only to those parts of the Right of Way intended for other facilities. The SDT has also further clarified the concept in the white paper. **2. Due to the directive given by FERC Order 693 your suggestion for removing some lines above 200 kV from the Standard's Applicability was not considered. (Excerpt from order 693 paragraph 706 "we did not intend to make this Reliability Standard applicable to fewer facilities than it currently is with the 200 kV bright line applicability, but to extend the applicability to lower-voltage facilities that have an impact on reliability").** **3. Reporting requirements are included in standard in the second posting.**	
Progress Energy Carolinas	To avoid interpretation errors and provide clarity, the Applicability section for Facilities (4.2) of FAC-003 should include a statement that the standard only applies to vegetation within the Active Transmission Line Right of Way. For example, a fall-in from outside of the Active Transmission Line Right of Way that causes a sustained outage is not a violation of this standard. Any encroachment/outage initiated by vegetation falling from outside of the Active Transmission Line Right of Way should be excluded from violations. The Critical Clearance Zone concept is academically elegant, but when applied in the field, it presents significant implementation, interpretation and enforcement issues: the complexity of determining compliance could have the unintended negative consequences to reliability; removal of vegetation will likely be delayed because of the complexity and accuracy required to determine compliance prior to tree removal; certification that no violations have occurred will require lengthy and costly calculations and survey measurements; the standard refers to Ratings in the determination of line sags and Ratings is not a tightly defined term, PRC-023 requires relays to hold lines in beyond the line Ratings; how will PRC-023 requirements be factored into the Critical Clearance Zone concept. The Critical Clearance Zone concept introduces more complexity and ambiguity into the standard than it resolves. The drafting team needs to develop an alternative to the Critical Clearance Zone concept that is simple, easy to apply and clearly defines at what point a violation occurs. There are over 158,000 line miles of AC Transmission above 200kV in the United States, covering a Right of Way area potentially as large as 3,000 to 4,000 square miles (an area roughly equivalent to Rhode Island and Delaware combined). With billions of stems of managed vegetation, in and along the right of way, even six-sigma performance would result in a number of outages on a system this large. With countless VM processes and assessments that take place daily, it is unrealistic/unreasonable to expect zero-tolerance for random vegetation events (the transmission system is planned/operated to handle at least any single contingency).
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. **The exclusion you request for vegetation falling through the MVCD, regardless of its being form inside or outside the right-of-way, has been added.** **Due to the industry impact that arises from zero tolerance for vegetation-related sustained outages, the Drafting Team tried several approaches but could not find a mechanism in the standard development process to establish a non-zero threshold for outages that was acceptable to FERC staff, because Standard revisions may not lead to less emphasis on reliability.** **The PRC-023 Standard seeks to ensure that transmission protective relays are properly set such that they do not trip a transmission element unnecessarily. This FAC-003 Standard seeks to prevent vegetation related Sustained Outages by requiring Transmission Owners to maintain their**	

Organization	Question 18 Comment
Active Transmission Line Rights of Way to be sufficiently clear. These two Standards are not mutually exclusive nor conflict with each other.	
Southern California Edison Company	SCE notes that Section C (Compliance) is incomplete and that the associated levels of Non-Compliance listed in FAC-003-1 may be different from those proposed for FAC-003-2. SCE reserves the right to revise its initial comments and submit additional comments regarding the requirements, measures and compliance portions of FAC-003-2.
Response: The SDT thanks you for your comments. Draft 2 will be a complete Standard for you to review.	
SERC OC Standards Review Group	The SERC OCSRG recommends that the definition of "Active Rights of Way" be revised as follows: "A strip of land, designated by the Transmission Owner, that is occupied by active transmission facilities. This corridor does not include the inactive or unused part of the Right of Way set aside by the Transmission Owner for other facilities or uses." The SERC SOSRG recommends that this standard should exclude radial to load facilities and, for consistency, all 200 kV and above lines should not be included in the standard unless they meet the same requirements as sub 200 kV lines.
Response: The SDT thanks you for your comments. The SDT opted to retain the "bright line" of 200kV without further qualifications such as radial to load transmission facilities, due to the directive given by FERC Order 693 (paragraph 706 "we did not intend to make this Reliability Standard applicable to fewer facilities than it currently is with the 200 kV bright line applicability, but to extend the applicability to lower-voltage facilities that have an impact on reliability".	
Western Utility Arborists	Any standard that is developed should not contain advisory-type language? it should be declarative in tone. For example, in R1.4, the ending clause that begins "and may include actions" should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program. ADDITIONAL COMMENTS We have prepared, and will submit via email, additional comments regarding our online submission. If the ability to submit them electronically is not available on this website, we will send the complete document via email to Harry Tom and would ask that it be reviewed and considered by the drafting team.
Response: The SDT thanks you for your comments. The phrase in R1.4, "and may include actions" has been removed from the revised standard in support of your suggestion. **Please refer to the various responses to your comments provided in the individual questions. The changes to the standard in this reposting and the responses to your comments on questions 1-17 are intended to serve as a reply to your various comments.**	
Florida Power & Light	FPL believes the Vegetation Management standard should concentrate on grow-in tree issues that contribute to cascading or blackout events as stated in the purpose statement. Fall-in trees from either on or off ROW do not in-and-of themselves cause cascading or blackout events. Transmission systems are appropriately designed to handle incidental outages under N-1 conditions which are the case in fall-in type outages. Requirements relating to fall-in and blow-in outages (R6 and R7), which deal with incidents resulting from

Organization	Question 18 Comment
	force majeure or acts of God, should be removed to allow resources to be allocated to addressing events related to grow in interruptions. Because of an utter lack of control or such situations, no Standard or regulation places a duty on one to control force majeure or acts of God, yet that is precisely what R6 and R7 intend to do. If R6 and R7 stay in its current form, this will be yet another reason why this Standard as written will be unenforceable. FPL recommends the following approach. The entire US Transmission system was built under the National Electric Safety Code (C2). That code uses the Reference Component as the initial building block for establishing the lowest height of a conductor for all operating and designed environmental conditions. Over most open land this distance is 14 feet. FPL recommends creating a new requirement to clearly define a trimming standard. New Requirement At time of trimming, trees under conductors should be trimmed or removed so that the average growth would remain below the Reference Component of Rule 232 in the National Electric Safety Code C2. The wire zone should extend to the blowout distance calculated at 39 miles per hour (Fresh Gale) not to exceed the Active Transmission Right-of-Way. Where the Transmission Owner can not achieve that clearance, they shall have a permanent (ex. raised conductor) or interim (ex. short trim cycles) corrective action plan in place to prevent tree wire conflicts. Permanent corrective action plans should reside in the Transmission Owner's vegetation program record keeping system (database) for application when that line is maintained or inspected. Trees to the side of the ROW should be maintained at the edge of the Active Transmission Right-of-Way. The value in this approach is in its application by arborists and tree trimmers in field conditions. This approach is clear and measurable without a surveyor or an engineer present. The line design calculations were made to the NESC Standard at the time the line was built and incorporate all potential conductor locations within its flight path. As it stands now if there is a violation to R4, R5, R6, or R7 it is already too late. The standard should seek to identify and correct poor performers before they create a reliability threat to the system. In the field, a poor performer has many trees close to the line and will have to do many emergency cuts. It will also have more momentary interruptions before it has a single Sustained interruption. Sustained Interruptions have a history of contributing to cascading and blackout events. The standard should measure performance and penalize poor performance. The changes below reflect performance measurements with a graduated penalty applied to the metric. Change R2 to read Each Transmission Owner shall implement its Imminent Threat procedure when the Transmission Owner has knowledge, obtained through normal operating practices or notification from others, that the tree / conductor distance is less than the minimum clearance distance as specified in Table 2 of ANSI Z133.1-2006 (the minimum approach distance for qualified line-clearance arborists or qualified line-clearance trainees). Transmission Owners are to document and report activation of the Imminent Threat Procedure for violation of Table 2. Activation of the Imminent Threat Procedure for other causes shall not be reportable. The Violation Severity level should read: Activation of the Imminent Threat Procedure for encroachment of Table 2 of ANSI Z133.1-2006 (the minimum approach distance for qualified line-clearance arborists or qualified line-clearance trainees) has the following severity level: Lower ? Greater than 5 per 1000 miles of line and less than 7 Moderate ? Greater than 7 per 1000 miles of line and less than 9 High - Greater than 9 per 1000 miles of line and less than 13 Severe - Greater than 13 per 1000 miles of line

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	Trees inside of Table 2 can only safely be trimmed under a clearance from the system operator, using special techniques under a line right of way from the system operator, or by a lineman with a live line permit from the system operator. No utility wants to let a tree get so close to energized lines such that it has to take the line out of service for a tree trim. It should be noted that Table 2 represents an established industry standard which is normally found placarded on the side of every tree trimming easement truck and bucket truck. It is minimum knowledge for every qualified line-clearance tree person under OSHA regulations. This is a distance that field personnel understand. New R5 to read: Each Transmission Owner shall minimize Momentary Outages of applicable lines due to vegetation growing into a conductor with the following exceptions:? Sustained Outages of applicable lines that result from natural disasters.? Sustained Outages of applicable lines that result from human or animal Activity. The Violation Severity level should read: Lower ? Having Momentary Outages Greater than 3 per 1000 miles of line and less than 6 Moderate ? Having Momentary Outages Greater than 6 per 1000 miles of line and less than 8 High - Having Momentary Outages Greater than 8 per 1000 miles of line and less than 12 Severe - Having Momentary Outages Greater than 12 per 1000 miles of line New R6 to read: Each Transmission Owner shall minimize Sustained Outages of applicable lines due to vegetation growing into a conductor with the following exceptions:? Sustained Outages of applicable lines that result from natural disasters.? Sustained Outages of applicable lines that result from human or animal Activity. The Violation Severity level should read: Lower ? Moderate ? High - Having Sustained Outages Greater than 1 per 1000 miles of line Severe - Having Sustained Outages of 2 or greater per 1000 miles of line These VSL's listed above constitute a strawman for discussion. The drafting team could request historical performance data from Transmission Owners to statistically evaluate where the VSL should be set. As time progresses, future performance data could be re-evaluated to reset the limits. These changes bring the standard back in line with measurable and auditable requirements which provide practical field measurements to the personnel who can make the difference. These parameters provide measurements to indicate the tree health of the system. On a separate note, FPL believes that clarifying information captured in footnotes within the standard should specifically be referenced and made part of the standard. These notes add clarity and better define the standard requirements.

Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive

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industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. The Drafting Team reviewed the exclusion in R6 and R7 and reached consensus that the stated exclusions are adequate to exclude force majeure or acts of God. This posting includes under R1 the new section 1.6. That would make the proposal you offer related to maintaining the height of trees above ground level to be a method for the TO to select. The language also allows TOs to select a separation distance between the conductor and the vegetation. When lines traverse terrain with significant changes in elevation within spans the latter method may be more practical. Changes made to utilize the MVCD as observed in real time will provide the clarity and measurability you requested. R2 has been revised to ensure that the process is used only for conditions that require immediate actions to prevent a sustained outage. Other factors which under some conditions would not pose an imminent threat of a sustained outage were purposely omitted to provide clarity and consistency of application. Since R2 is binary requirement its VSL cannot be gradated as you suggest. R5 has been left as a binary requirement with a zero tolerance in lieu of a gradated metric in the requirement as you suggest. Due to the industry impact that arises from zero tolerance for vegetation-related sustained outages, the Drafting Team tried several approaches but could not find a mechanism in the standard development process to establish a non-zero threshold for outages. Momentary outages are purposely not included because of the challenges they pose during investigation. These problems often lead to unreliable, inconsistent, false, or missing reports. Furthermore momentary outages caused by vegetation have not been a historical cause of cascading or widespread outages.	
Santee Cooper	The SDT should clarify that Transmission lines operated at 200 kV and above is for lines that are network facilities. Radial load transmission facilities operated at 200 kV and above should not be subject to this standard as they would not lead to SOLs or IROLs. M2 requires evidence that a Transmission Owner implemented its imminent threat procedure upon knowledge of a Critical Clearance Zone breach. M4 requires evidence that there were NO encroachments into the Critical Clearance Zone. These two measures are in conflict with one another. If a utility provides evidence for M2 then they are in violation based upon M4.M4 and M5 requires a utility to provide "proof to the negative". These measures should be removed from the standard. R10, R11, M10, and M11 should be removed from this standard as critical facilities are identified through the PRC standards.
Response: The SDT thanks you for your comments. Regarding your request to line applicability to only network lines above 200 kV FERC in order 693 paragraph 706 stated “we did not intend to make this Reliability Standard applicable to fewer facilities than it currently is with the 200 kV bright line applicability, but to extend the applicability to lower-voltage facilities that have an impact on reliability”. The standard drafting team therefore does not see that honoring your request as one that would be	

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permissible. **Regarding the conflicts you cite between M2 and M4, please note the revisions in this posting for R2, R4 and the associated measures. The conflict you reference should now be resolved since the distance in R4 is not the exclusive basis for implementing R2 and the concept of the "CCZ" has been removed from the revised standard.** **In M4, the language is now changed to remove the "proving a negative" dilemma.** **There is a 200 kV bright line for applicability in this standard; therefore it is appropriate for the applicability for sub 200 kV lines to be determined within this standard in lieu of the PRC standards.** **Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time.**	
Southern Company	We would like to re-emphasize our concern over the zero tolerance philosophy of FAC-003-1 which is continued in this proposed revision. FAC-003 has been singled out as the only zero tolerance NERC standard. Compliance should not be based on the encroachment of vegetation into a theoretical, pre-defined zone, but on the occurrence of a sustained outage, as stated in the document's Purpose Statement. We agree with the philosophy utilized in other NERC standards where a clearly discernible compliance event signals a review of the Transmission Owner's plans, policies, and procedures to determine the effectiveness of the entity's programs and spirt toward compliance. Applicability Section 4.2 describes the Facilities pertinent to this Standard. Recommendation is to restructure the sentence by relocating the parenthetical phrase: Transmission lines operated at 200kV or higher, and transmission lines operated below 200kV designated by the Reliability Coordinator as being subject to this standard ("applicable lines") including but not limited to those that cross lands owned by federal, state, provincial, public, private, or tribal entities. Requirement R3Recommend rephrasing to say: Each Transmission Owner shall conduct vegetation inspections of all applicable lines in accordance with the frequency specified in its transmission vegetation management program. Requirement 10The standard does not mention whether or not the results of this specific assessment methodology are supposed to be compiled and maintained. The resulting information could be labeled as sensitive and possibly critical since the loss would place the grid at an unacceptable risk of instability, separation, or cascading failures. If the resulting information becomes auditable (subject to discovery and posting) then precautions must be taken that are comparable to those designed to preserve the integrity of critical assets or critical cyber assets. We would like to express our sincere appreciation and thanks the drafting team for their efforts.
Response: The SDT thanks you for your comments. **Due to the industry impact that arises from zero tolerance for vegetation-related sustained outages, the Drafting Team tried several approaches but could not find a mechanism in the standard development process to establish a non-zero threshold for outages that was acceptable FERC staff**	

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because revisions to a Standard may not lead to less emphasis on reliability. **The standard has been revised to remove the violation for encroachment into a theoretical zone and is now based on an observed encroachment in real time inside a distance where flashover becomes a possibility.** **The Drafting Team considered the applicability wording with the (“applicable lines”) to be acceptable as written.** **R3 has been revised as you recommended.** **The Drafting Team agrees that documentation regarding the methodology used to determine applicability of lines below 200 kV should have similar precautions for confidentiality as other critical assets or critical cyber assets.** **The issue of transmission line applicability is addressed in FERC Order 693.**	
Bonneville Power Administration	There is a typographical error / omission in the Technical Reference on Page 36, which states, "R6. Each Transmission Owner shall prevent Sustained Outages of applicable lines due to the blowing together of vegetation and a conductor with (sic) Active Transmission Line Right of Way) operating within design blow-out conditions) with the following exception: . . . " I believe the intent is for the statement to read "due to the blowing together of vegetation and a conductor WITHIN Active Transmission Line Right of WAY". This change is needed to make the technical reference consistent with R6. as it appears in the Standard, the definition of Active Transmission Line Right of Way on Page 5 of the Technical Reference, as well as the terminology used on Page 37 in describing Fall-into outages. This needs correction.
Response: The SDT thanks you for your comments. The technical reference error is noted and has been corrected by the SDT.	
Public Service Electric and Gas Company	These comments were prepared by Richard Wolowicz, Manager Vegetation Management, on behalf of Public Service Electric and Gas Company ("PSE&G"). PSE&G also joins with and supports the comments filed by the Edison Electric Institute (EEI) in this matter.
Response: The SDT thanks you for your comments. Please see our response to EEI.	
FirstEnergy	FE provides these additional comments for consideration: 1. Regarding the Applicable Facilities - Section 4.2.2 would be more appropriately placed under Sec. 5 "Effective Dates" since it deals with the timeframe the Transmission Owner has to implement its Transmission Vegetation Management Program on sub-200 kV lines.-Section 4.2.3 - We suggest removing this section. First energy does not agree that this standard should dictate the amount of time a Transmission Owner has to obtain compliance with this standard for newly acquired transmission lines. It should be the responsibility of every organization to "self-report" its compliance issues and planned mitigation plans for all standards when they acquire new lines or facilities. If the SDT believes this should be explicitly stated, then it should recommend to NERC that explicit language be placed in the NERC Rules of Procedure. No other standards set timetables for newly acquired facilities and this standard should be no exception. 2. Regarding R1.1, this subrequirement requires the Transmission Owner to specify the methodologies it uses to control vegetation. It

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	should be clear that not all of these methodologies are required to be deployed in every situation (as explained in the white paper pg.12). We suggest rewording the requirement as follows: "R1.1. Specify the methodologies that the Transmission Owner may use to control vegetation." 3. R1.5 requires a process for "interim corrective action" be specified in the Transmission Vegetation Management Program. However, the standard does not explicitly specify that this corrective action be implemented when the Transmission Owner is constrained from performing vegetation maintenance as planned. 4. As written, in addition to the responsible RC, R10 may imply that this requirement is also the responsibility of the Transmission Owner(s) and neighboring RC(s) due to the use of the term "jointly". Also, R10 should require the RC submit the list of designated lines below 200 kV to the Transmission Owner(s) and neighboring RC(s) within a reasonable time-frame after its completion. We suggest rewording and addition of subrequirements to R10 as follows: R10. Each Reliability Coordinator, in consultation with its Transmission Owner(s) and neighboring Reliability Coordinator(s), shall prepare and keep current a list of designated applicable lines that are operated below 200kV, if any, which are subject to this standard. R10.1. The RC shall submit the list to the impacted Transmission Owner(s) within 30 calendar days of completion and/or revision. R10.2. The RC shall submit the list to its neighboring RC(s) within 30 calendar days of completion and/or revision. Lastly, measure M9 will need to add sub-measures for the proposed additions above. 5. Requirement R10 should require that the RC ONLY uses the assumptions detailed in R10.1 and R10.2 to designate a line as significant. Also, R10.1. should reference the IROL methodology standard FAC-011 since it directly ties into this requirement. Also, in R10.2, "grid" should be replaced with "BES" and the term "failures" is not necessary. We suggest re-wording R10, R10.1 and R10.2 as follows: R10. Each Reliability Coordinator shall document its method for assessing the reliability significance of sub-200kV lines and shall be based only on the following: R10.1 Transmission lines whose loss would result in the exceedance of an Interconnection Reliability Operating Limit (IROL) as determined by standard FAC-011. R10.2 Transmission lines whose loss would place the BES at an unacceptable risk of instability, separation, or cascading.

Response: The SDT thanks you for your comments.

The placement of Section 4.2.2 was chosen to allow the TO time to bring those lines into compliance which are identified by future studies well after the effective dates in Section 5.

The SDT chose to leave Section 4.2.3 as it does provide a reasonable time allowance (limitation) to bring the subject lines into compliance. {note for a newly acquired line to have not previously been subject to the standard it may have been 1) owned and operated by a private entity such as a mining company that was not connected to the grid, 2) was a de-energized line not in operation until it was acquired by the TO, 3) was previously operated at

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less than 200kV but was insulated for an operated at 200kv or higher, or 4) some similar situation to 1-3 above} The SDT sees this Section as following the Rules of Procedure Standard Applicability Section as noted on page 9 to "identify any limitations on the applicability of the standard based on electric facility characteristics". **The SDT modified Requirement R1, Part 1.1 as suggested. The standard does not explicitly state that the interim corrective action process in 1.5 must be implemented. The SDT suggests that the other requirements in the standard related to outages and imminent threats and encroachment provide necessary and sufficient incentives for TOs to utilize the process when and if required.** **R9 and R10 (now R10 and R11) have been revised to replace the RC with the PC as the applicable functional entity. The verbiage "in consultation with" has been replaced by "shall consult with its Transmission Owner(s) and neighboring Planning Coordinators to obtain input to develop the list". Since this list is prepared by the PC for the TO to know of any sub 200 kV line(s) that the TO must maintain, the SDT does not see a benefit to adding a requirement that the PC will provide the list to the TO.** **The SDT chose to keep the word "grid" in lieu of BES to avoid confusion related to the fact that the BES generally includes all lines above 100 kV as defined by the Regional Reliability Organization and this standard does not.** **Other changes were made in the language of R9 and R10 to which incorporate parts of recommendations from other commenters and FE. Requirement R10, Parts 10.1 and 10.2 were redundant, and Part 10.1 was deleted and Part 10.2 was translated into a separate requirement, R11.**	
Midwest ISO Stakeholders Standards Collaborators	FAC-003-1 lacks clarity that is essential for understanding what is necessary for compliance. The proposed FAC-003-2 needs to be simplified to aid with field implementation and compliance interpretation. Currently, it does not provide the clarity and simplification needed by Transmission Owners and regulatory bodies to enhance reliability.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. These changes should add the clarity and simplification that your and other commenters suggested was needed for field implementation.	
SERC Compliance Staff	SERC staff continues to find the Applicability section of the standard to be confusing and contentious. While we recognize it is the intent this section to make the standard applicable t all entities that own transmission lines that operate at greater than 200 kV, this section should not be written to be applicable to transmission lines. Only registered entities can be held accountable for compliance with the standards. SERC staff believes the applicability should be rewritten to include Transmission Owners, Distribution Providers, and Generation Owners that own transmission lines with the characteristics defined in Section 4.2. This would eliminate the need to make register, for example, a Distribution Provider that own a 230 kV line that serves load as a Transmission Owner and make them subject to the requirements of FAC-001 and FAC-002. SERC Staff also suggest the applicability could be handled as it is in PRC-005-1 where the applicability is qualified as 'distribution provider that owns..' and 'generator owner that owns..' or in a similar manner that captures the appropriate subgroup but does not include unintended entities. SERC Staff believes a flashover between vegetation and overhead ungrounded supply conductors that occurs, whether or not the

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	flashover results in a Sustained Outage, is clear evidence of an unallowable encroachment of vegetation into the space that should be avoided and thus should be identified as evidence of a violation of the standard. SERC staff has also found that excluding outages resulting from "earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner?" results in inconsistencies in reporting because of the inconsistency of the Transmission Owners' definitions of same. If such exceptions are to be allowed, a consistent method of determining the acceptability of those exemptions should be pursued.

Response: The SDT thanks you for your comments.

The intent of the Facilities section under Applicability which you suggest is confusing and contentious, was chosen to follow the Reliability Standards direction under Applicably, specifically "if not applicable to the entire North American bulk power system, then a clear identification of the portions to which the standard applies…"

The issue you raise with respect to Distribution Owners and Generation Owners does not appear to be supported when one reviews the definition of a Transmission Owner in the NERC Glossary "The entity that owns and maintains transmission facilities." The SDT is concerned that your suggestion will add confusion to the standard." PRC-005-1 properly addresses the coordination needed between transmission protection and the interface with distribution protection at the point of transformation. There is no comparable expectation for vegetation maintenance on the low voltage side of a transmission to distribution transformer to be subject to this standard. Simply put, either someone owns transmission or does not. It is of no matter whether they may also be a DP or GO. Until the functional model includes provisions to state that "all transmission is not equal", the applicability should remain.

Your concern about flashovers that do not result in Sustained Outages needing to be stated as violations of this standard has been discussed at length by this SDT. The interest is to have a Standard that is not subject the levels of uncertainty associated with any automatic operation which is returned to service by either manual or automatic means. These events are very often not possible to identify, many times misidentified often occur during conditions that have several possible explanations (such as high winds blowing conductors together, wind-blown debris, lightning, contamination flashovers during the onset of wind and rain storms) and do not have a historical basis for ever creating a cascading event. Inclusion of these events as violations in the standard could also cause significant additional costs for extensive investigations by TOs to prove their "innocence" for events that any properly designed and operated transmission system should withstand with no more challenge that the far greater number of lightning, and equipment failure events (cross-arms, insulators, conductor splices, poles) nor ever been the subject of momentary opera being.

Members of the SDT attempted to get the TADS reporting requirements to clearly identify those faults on transmission lines that required maintenance to return the line to service. If such a definition was entertained, then a great deal of the uncertainty is cleared. However there are still conditions where trees and poles are found down after apparent high wind conditions in locations remote to the nearest weather reporting station that depend on assumptions as to which fell first the pole or the trees. The zero tolerance nature of this standard and the Penalty Matrix values should not be tied to anything with a high degree of assumption and uncertainty. Therefore the standard has been revised and worded to have the violation of MVCD as observed in real time.

As an added note there is unnecessary confusion caused by simply labeling the automatic operation line operations as momentary, sustained, and/or locked-out. If a line is not reclosed within moments of the automatic interruption, but is later "test closed" was the line truly unavailable? Was the

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reclosing signal/command properly performed initially? Did the TOP ever truly lose control of this line if all that was required was another close attempt? The true nature of the loss of a line is manifested when it is known that a clearance must be issued such that the line is removed from the TOP's control. **The SDT has reviewed the data on vegetation related reported outages on the NERC website. There are 223 reports of outages in that data covering the period January 2004 to March 2009. The associated documentation with these events indicate that TOs are supplying supportive information to indicate that the level of any disaster exclusion is sufficient to identify that design criteria was exceeded. Further specifics on the threshold for each disaster would not ensure that weather data would be adequate to support each location/situation.**	
ITC HOLDINGS	V1 was a better written standard and had clear requirements on reporting and who was to report violations etc. When and how are violation to be reported is not mentioned in the V2. The standard should clearly identify all reporting requirements. Standard development should focus on practicality for the field personnel in terms of implementing the standard and enforceability. Version 2 is not as user friendly for field personnel and ambiguous at best which requires an impractical and unrealistic level of performance from the industry. This standard needs to stress that it applies to vegetation within the Active Transmission Right of Way. Vegetation from outside the active ROW, falling through the Critical Clearance Zone should not be a violation. V2 needs further clarification of the definition of the active ROW.
Response: The SDT thanks you for your comments. The issue of reporting has been addressed in the compliance section of the revised standard. **The changes made to R4 focus on the practicality for field implementation that you suggest. The exclusion you request for vegetation falling through the MVCD, regardless of its being form inside or outside the right-of-way, has been added.** **The definition of the active right of way was debated at length and determined to be best stated in its current form.**	
Exelon	Applicability. 4.2.2 is unclear. If 4.2.2 is intended to cover Generator Owner interconnections, say so uniquivocally. Do not rely on future changes to the NERC Registry Criteria or other "global" solutions if the intent is to make the standard applicable to Generation Owners who own generator leads. Exelon would like to reemphasize our concern with implementing the requirements if the Gallet equation derived Critical Clearance Zone is used. ANSI A300 part 1 and part 7 should be part of the standard as they provide independently recognized valid methods and guidance to conduct maintenance on the ROW corridor.
Response: The SDT thanks you for your comments. **The issue you raise with respect to Generation Owners does not appear to be supported when one reviews the definition of a Transmission Owner in the NERC Glossary "The entity that owns and maintains transmission facilities." The SDT is concerned that this suggestion to add the Generation Owner will add confusion to the standard." The SDT does not agree there is ambiguity. Either an entity is a TO or not.** **The Gallet Equations distances were chosen in lieu of ANSI A300 for clearances because the Gallet is a distance that is necessary to prevent flashover.**	

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The ANSI values are related to worker and public safety not flashover between the conductor and the vegetation.	
Central Maine Power Company	The White paper is an important support document and should remain as an attached reference to FAC 003. The white paper should clarify that capable tree species should always be removed from the border zone, except in selected areas where topography includes deep ravines.
Response: The SDT thanks you for your comments. The standard was designed to allow the Transmission Owner the flexibility to design its TVMP. Further, ANSI A300 is also footnoted in the standard as a "best practice". The White Paper will remain a reference for this Standard and text has been added to try to provide additional guidance as you suggest.	
American Electric Power (AEP)	The definition for Critical Clearance Zone (Critical Clearance Zone) on page 2 of the proposed draft Standard does not specify the Rating (summer, winter, normal, emergency, etc.). This suggests that different Critical Clearance Zone s apply at different times of the year and thus that vegetation in the area might be outside the Critical Clearance Zone at certain times of the year and inside the Critical Clearance Zone at other times. AEP suggests that this may not have been the intent of the drafting team. Also, the term "design blowout" is not defined; thus, it appears that it will be up to the Transmission Owner and the auditor to determine the bounds of the Critical Clearance Zone . AEP again suggests that this may not have been the intent of the drafting team. Requirement R9 contains the clause "within the extent of its easement and/or legal rights". This intent of this clause is unclear and its rationale is not obvious. AEP suggests that this clause be removed or at least reworded for clarity.
Response: The SDT thanks you for your comments. The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. The verbiage you suggested removing form R8 (now R9) was removed. Finally, the new Requirement R1 should address the concern about sag and blowout in that it talks about planning to keep vegetation out of all positions the conductor may be for all design conditions.	
Platte River Power Authority	The white paper ensures consistent interpretation of the standard. Perhaps the lack of such a paper in the first version of the standard contributed to the varying interpretations.
Response: The SDT thanks you for your comments. The White Paper will accompany this Version as a Reference document.	
City of Tallahassee	Attachment I. Titles are different between page 8 and 9. Page 8 should have (D) after Distances. Page 9 should have indication that it is "continued" since the table spans multiple pages.
Response: The SDT thanks you for your comments. The SDT has reformatted the table in Attachment 1 of the Standard.	
Northern California	Section A. 5. Effective Dates: This is extremely vague and I would not know the actual effective date. Whose regulatory approval is

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Power Agency (NCPA)	needed? If this is meant to leave flexibility between FERC and the Canadian entities, please write it that way. Most effective dates are clear and concise, i.e., "the first month following approval by FERC". Let's clear this up and avoid a subsequent interpretation request.
Response: The SDT thanks you for your comments. The wording of this portion of the standard (the Standard's effective date) is governed by NERC policy. The process for approval is different in different jurisdictions – some Canadian Provinces approve a standard when it is approved by the NERC Board of Trustees, other Provinces have other mechanisms for approving standards. For entities that operate in the United States, the FERC is the regulator that must approve the standard. As written, the standard will become effective in the United States the first calendar day of the first calendar quarter one year after FERC approval.	
Northern Indiana Public Service Company	While I very much respect the industry commitment and expertise of the drafting team members, the resulting revised standard reflects an effort to "revolutionize" the standard, when an "evolution" of the current standard would better serve the interests of system reliability. The kinds of wholesale changes proposed in this revision evoke real concerns about governmental regulations being a moving target and in many aspects, backs away from requirements that have led to real progress in UVM made since the 2003 blackout. For example, our company has invested tens of thousands of dollars and countless man-hours to comply with provisions of the existing standard only to see them simply done away with under the proposed revised standard. These investments were made based on an industry consensus standard as well as a realization that the requirements were reasonable and essential to improving system reliability. Where is the evidence that the current standard is not working as intended? What has changed in the last few years to warrant a complete re-write of the current standard? Most UVM professionals will agree there are some changes that need to be made to address FERC's concerns and to clarify intent. However, as presently written, I will recommend our T.O. vote against adoption of FAC-003-2.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The Critical Clearance Zone concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. Moreover, certain language changes were needed to comply with directives in FERC Order 693. The changes proposed are meant to capitalize on programs already implemented, not to discard them.	
Tampa Electric Company	Good start. However, this will need additional work and review predicated on the above comments.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time.	
Orange and Rockland Utilities Inc.	Clearance 1 has been eliminated from this draft. Version 2 as drafted only requires that Transmission Owners address vegetation that approaches the Critical Clearance Zone . This is essentially equivalent to Clearance 2 in version 1, a minimum clearance. Although unlikely this could result in some Transmission Owners adopting a just in time vegetation management concept that focuses on

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	maintaining minimum clearances, rather than removing incompatible vegetation or achieving greater clearances. Although R1 requires Transmission Owners to design their Transmission Vegetation Management Programs to control vegetation there is no clear requirement to address incompatible vegetation early and aggressively. The drafting team should revisit this and consider returning to some form of Clearance 1 or requiring the Transmission Vegetation Management Program to address removal of incompatible vegetation within their easement rights.
Response: The SDT thanks you for your comments. **The SDT did revisit and reconsider reinserting a Clearance 1. The issue of how and when to remove or control “incompatible vegetation” was also revisited. The SDT decided to leave C1 and the methods to control (or remove) “incompatible vegetation” to the discretion of the TO. Such discretionary measures do not meet the qualifications to be a requirement within a standard.** **Please take a comprehensive look at all the requirements in the standard we are now re-submitting with this posting. Compliance with these requirements will ensure that the TO maintained vegetation such that 1) no controllable sustained interruptions have occurred, 2) no imminent threats were left unaddressed, 3) all the separation distances between the conductors and vegetation every time they were observed were greater than the distance necessary to prevent a flashover.** **Compliance with each of the above requirements can be achieved with inspection and pruning cycles on a frequent basis such as annually, or on a longer term basis such as every 4 years where warranted by local conditions. There are numerous examples in the industry of these different approaches being both appropriate and effective. Just because a “shorter cycle” is utilized, does not mean that a compromised or “just-in-time” concept is has placed the adequate level of reliability of the grid at risk.**	
American Transmission Company	FAC-003-1 lacks clarity that is essential for understanding what is necessary for compliance. The proposed FAC-003-2 needs to be simplified to aid with field implementation and compliance interpretation. Currently, it does not provide the clarity and simplification needed by Transmission Owners and regulatory bodies to enhance reliability. Requirement 1.3: The proposed requirement does not allow enough flexibility for making changes to the Annual Plan. We believe that changes to the Annual Plan should be allowed even if that means delaying something until the next Annual Plan. Our Proposed Changes: Have an annual plan that identifies the applicable lines to be maintained and associated work to be performed. Adjustments to the annual plan are permissible. We believe that our proposed language accomplishes the SDT's intent while allowing for appropriate flexibility.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. Those changes, including the removal of the concept of the CCZ, address and provide the clarity and simplifications you suggest are needed for field implementation of the standard. R1.3 has been revised for to provide clarity. **These R1.3 changes do not explicitly remove the “within the year” clause as you requested, however we do not see the inclusion of that language as restricting appropriate flexibility. It is expected that the annual work plan will be flexible to adjust to changing condition and findings which occur after the plan is first issued for the year, then adjusted within the year as appropriate. Adjustment made within a year may mean accelerating work to the current year that was not in the current year’s plans as well as extending work that was initially planned for this year into the future. And when**	

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<tr><td colspan="2">disasters occur, the SDT has addressed an appropriate extension.</td></tr>
<tr><td>Xcel Energy</td><td>Attachment 1, Table I- Change the title of the table from "Proposed Minimum Vegetation Clearance Distances" to "Critical Clearance Zone Distances". The reason being is that the general public could interpret this table to mean that this is all the clearance that is required by a utility at the time of pruning.

Section C, Violation Severity Levels- There is some inconsistency between the C.2 chart and the contents of the Standard and the White Paper. For example, the White Paper specifies that an exception to an R6 blowing together violation would exist for sustained winds of gusts of 45 miles per hour or greater.

As to R7, the Standard itself notes that a violation only occurs if the vegetation falling into the line is from within the ROW ? C 2 does not incorporate that requirement. There are two approaches: either note the exemptions within the C 2 chart, or add a footnote to the chart along these lines: "This chart summarizes various provisions, the details of which are more fully set forth in the Standard and White Paper?. We would recommend the later approach.

General suggestions:

1) It appears that the FAC-003 Standard is the only "zero tolerance" standard, in some respects. Is this reasonable?

2) There appears to be "advisory" language in this version of the Standard. This type of language should be part of the White Paper, not the Standard itself.

3) Utilities need more support from FERC to deal with regional roadblocks within the USFS regarding the implementation of IVM. The Memorandum of Understanding is not universally accepted within all regions of the USFS.</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment parts of those changes address or remove the issues you raise for exemption and footnotes for Table 1.

Table 1 in not intended to be used by TOs to determine how much to prune. This table provides the actual physical separation distances, which if observed, will ensure that flashover from the line to vegetation will not occur. When conditions exist such that the separation is reduced the risk of flashover will become significant. The risk increases as the separation is reduced. Therefore this value represent a threshold which if not violated will prevent flashover, as such it is a valid physical basis for R4 compliance.

This standard allows the TO to use any combination of pruning, removals of vegetation at ground level, frequency(cycles) of planned maintenance, enhanced inspections, off-cycle corrective maintenance, etc to prevent violations occurring due to vegetation causing a non-exempted sustained outage or MVCD violation.

Due to the industry impact that arises from zero tolerance for vegetation-related sustained outages, the Drafting Team tried several approaches but could not find a mechanism in the standard development process to establish a non-zero threshold for outages that was acceptable to FERC staff because revisions to Standards may not produce less emphasis on reliability.</td></tr>
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The advisory language in R1.4 has been removed. **The SDT discussed with NERC and FERC the need for support with the USFS issues. The SDT concluded that FERC has no power to change the rights or restrictions within any permit or easement document across privately owned or publicly owned.** **Therefore any efforts to improve permits or reduce limitation on permits or easements on federal lands must be handled through other available methods.**	
Ameren	While FAC-003-1 lacks clarity that is essential for understanding what is necessary for compliance, the proposed FAC-003-2 needs to be simplified to aid with field implementation and compliance interpretation. Currently, it does not provide the clarity and simplicity needed by Transmission Owners to implement and regulatory bodies to monitor in a manner that will enhance reliability.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. Those changes address and provide the clarity and simplification you suggest are needed for field implementation of the standard.	
Long Island power Authority	1) Disagree with R1.1. The proposed standard is too lenient on the program documentation required for an effective program. R1.1 should include the words " the program will document the program objectives, method of site evaluation, the definition of action thresholds, the control methodologies, and how the monitoring program is established". There is a wide gulf between listing IVM methodologies and a vegetation program implementing A300. 2) CHANGE: Within Applicable Facilities listed in section 4.2 the phrase Transmission Line should be changed to Overhead Transmission Line. The NERC Glossary definition of transmission Line is: " A system of structures, wires, insulators and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances." The accompanying white paper states the standard is addressing the impact of vegetation growth on overhead transmission lines. The intent of this standard is the development and implementation of a vegetation management program for overhead transmission lines only. By specifically stating "overhead transmission lines in Section 4.2 there will be no possibility of an occurrence of an auditor requesting a vegetation management program for underground lines.
Response: The SDT thanks you for your comments. In R1.1 the SDT chose to direct the TO to specify the methods used to control vegetation vs specifying a menu of items that may not be applicable to several TOs due to the limited types of vegetation in their areas. The SDT considered the issue of overhead versus underground and concluded that no further clarification was needed. Further, ANSI A300 is referenced in the Standard as a best management practice. The SDT leaves up to the TO the extent to which it wishes to apply A300.	
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	I'm having trouble getting comments to "stick" in this section of the form. I have a general concern with the opening paragraph of R1. The wording seems to encourage a Transmission Owner to develop a Transmission Vegetation Management Program in a vacuum. The US Forest Service definitely wants input into the development of an annual work plan and USFS land use authorizations include a requirement for USFS approval of vegetation management plans. It seems much more reasonable to require the Transmission

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	Vegetation Management Program to reflect USFS or any other landowner resource management considerations. This tactic would require more "up front" work, but the end result is a plan which would reflect reasonable landowner input and where the disagreements could be settled ahead of time rather than being left for the night shift. I also believe that some kind of dispute resolution process is needed outside the control of either the Transmission Owner or the USFS. I think that NERC could fill that role very well.
Response: The SDT thanks you for your comments. Underlying landowner rights are outside the purview of this Standard. However, the SDT recognizes the value in "up front" input between landowners and transmission Owners. Notice that in this posting of the standard within Requirement 1 at 1.3.4 the transmission vegetation management program shall "take into consideration permitting and scheduling requirements from landowners and regulatory authorities". Such consideration should aid in addressing the issues you raise.	
Consumers Energy Company	The annual work plan should be designed to avoid vegetation growing into a violation of the Critical Clearance Zone or whatever minimum distance is acceptable. Since the plan can change throughout the year, it needs to be flexible, it should be stated that the plan at a minimum must provide adequate funding to prevent vegetation growth from violating the minimum clearance distance. The flexibility of change should be limited to changing to address emergent needs for vegetation management and not reductions in funding that delay maintenance in the hopes that additional funding at some future point in time will be adequate to remove the backlog of vegetation maintenance. The Purpose of the standard should be revised to state "(To maintain minimum clearance sufficient to avoid any vegetation-related Sustained Outages for all applicable conditions) for all Transmission Lines covered by this Standard" as provided by FERC in Order 693, Paragraph 731. The purpose as stated in FAC-003-2 waters down the intent of FERC to "improve the reliability" and is only applicable to "outages that could lead to cascading".
Response: The SDT thanks you for your comments. The purpose statement language was chosen to explicitly state the outcome to be achieved by this standard. The requirements themselves address, among other things, the Sustained Outages and minimum clearances along with the required supporting language. This separation between the purpose and the requirements appears more appropriate to the SDT. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. Further, funding is not an issue addressed by this Standard.	
National Grid	National Grid has the following comments: 1. Transmission Owners should be able to define their own inspection "year" and not be locked into a calendar year time frame. National Grid performs inspections at least once per vegetation growth year. Under our Vegetation Management Program, growth years are not skipped, and our inspections occur prior to new growth every year. For example, a transmission right-of-way may be inspected in December 2008 and the right-of-way is next inspected in February 2010. Under this scenario, the inspections occurred 14 months apart, but only one growth year occurred between inspections, and each inspection is ahead of the next year's growth. Transmission Owners need this flexibility to deal with regional growth rate differences and climate. 2. Section C., Compliance, of Draft Standard FAC-003-2 states "To be added". Issuance of Draft Standard FAC-003-2 should have been delayed for comments until all sections were complete. This section is likely to include the outage reporting and self-certification

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<tr><td></td><td>requirements. Transmission Owners need the opportunity to comment on these items.

3. With the elimination of Clearance 1 and reducing Clearance 2 clearances, there is concern that FERC will view Standard FAC-003-2 as a watered down version of Standard FAC-003-1.</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments.

1. It is recognized that most work management systems typically allow for planned work to be performed within a “band of dates” around a specific end date, such as one-third or one-fourth of an interval. These partial intervals allow for the normal variations that occur in work scheduling. When work is completed within that band of dates it is considered completed “as scheduled”. Compliance to R2 should be examined for the example conditions you offer since you are addressing the implementation of the inspections. If the frequency was stated in the vegetation management program as once per calendar year, and if the work was completed “as scheduled” then the TO would be compliant.

2. The compliance elements are included with the second posting of the standard and will be subject to stakeholder comments.

3. Effort were undertaken to address in the standard various elements for outages, imminent threats and clearances in a manner that was responsive to a substantial number of industry concerns. The SDT is striving to meet industry stakeholder concerns with a standard that will be approved by its ballot pool, the NERC BOT, and regulatory authorities, including FERC</td></tr>
<tr><td>Pacific Gas & Electric Co.</td><td>1) The standard should be clear that it applies to all Federal and Non-Federal land. PG&E further recommends additional language specifically dealing with Federal land such as application of ANSI A300.

2) The standard should specify applicability inside substations.</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments. This Standard states in the applicability section that all lands are subject to the standard. Further, ANSI A300 is footnoted in the Standard. Substation facilities are not included in this Standard. This will be addressed in the White Paper.</td></tr>
<tr><td>NV Energy (fka Sierra Pacific / Nevada Power Co.)</td><td>These comments were made with collaboration with other Western Utilities in a conference on this topic held in Denver. Any standard that is developed should not contain advisory-type language? it should be declarative in tone. For example, in R1.4, the ending clause that begins “and may include actions” should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program. NV Energy and the other Western Utilities support the development of this white paper as a way to help ensure consistent interpretation of the standard. Perhaps the lack of such a paper in the first version of the standard contributed to the varying interpretations by the auditors. The utilities understand however that this document is not a legal document and is not binding.</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments. Please refer to the various responses to your comments provided in the individual questions. (R1.4 was modified to eliminate the list of possible actions and the use of the word, “may.”)

The changes to the standard in this reposting and the responses to your comments on questions 1-17 are intended to serve as a reply to your various</td></tr>
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comments.	
San Diego Gas & Electric	We feel that any advisory-type language should be removed from the standard and replaced with wording that is in a declarative tone. We support the development of the white paper as a way to help ensure consistent interpretation of the standard.
Response: The SDT thanks you for your comments. The advisory-type language has been removed form R 1.4	
Hydro One Networks Inc.	Please see our comments on question 3.
Response: The SDT thanks you for your comments. Please see the response to comments on question 3.	
Edison Electric Institute	Overall Comments EEI strongly believes that companies are responding assertively to the requirements in FAC-003-1 and that the existing standard is effective in supporting an adequate level of reliability. The central issue with FAC-003-1 and the draft version 2 centers on circumstances where vegetation encroachments into clearance zones take place and do not result in interruptions. EEI understands that a potentially broad range of interpretations are being applied to the existing standard, resulting in potential violations due to clearance encroachments of any possible design position of the conductor being violations, as well as Sustained Outages. Version 2 should clarify this issue in the context of focusing the industry in the direction that is most effective in establishing an adequate level of reliability. The technical comments provided by EEI seek to address this critical issue. Quantitative analysis on vegetation-related line outages or violations made publicly available do not support the need for a substantive revision of the standard. Analysis needs to recognize a broader range of facts in a consistent manner. Analysis needs to consider whether violations resulted in a Sustained Outage, whether all outages and vegetation encroachment were voluntarily reported prior to enactment of Section 215, or the facts and circumstances surrounding violations. For example, while some entities may perceive a decline in industry performance, it may be that companies are reporting much more completely than in the past. Much more rigorous analysis is needed before concluding that the existing standard must be made tougher. Rather than focusing on whether the standard should be more stringent, EEI believes that the emphasis in the standard development process should focus on practicality, both for field personnel in terms of implementing the standard, and enforceability. Revisions to the existing standard should therefore seek to a) respond to issues raised by FERC in Order No. 693 b) where possible, clarify ambiguities in the requirements, and c) improve industry understanding, practicality, and enforceability. For example, it is impractical to seek development of a ?bright line? set of performance requirements. The standard needs to recognize both the diversity of the continent in terms of geography, topography, and climate, and the critical need to provide field personnel with workable performance requirements. Bottom line; it is very important to recognize that the ultimate goal of the standard is to ensure that vegetation management is conducted in order to maintain an adequate level of reliability, and the industry is achieving this goal. The standard should aim for increasing clarity in the requirements without sacrificing flexibility, since companies expect high monetary penalties associated with Sustained Outages caused by vegetation. In addition, a continued ?zero tolerance? approach to vegetation management will emphasize operational excellence. Seeking ?zero tolerance? on momentary outages is equivalent to pursuit of

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	operational perfection, which is achievable only at extraordinary expense to customers. Therefore, the Standard will be most effective if its elements encourage proactive behavior and provide incentives for Transmission Owners to identify and address vegetation clearance issues before they result in momentary interruptions or Sustained Outages. Vegetation Outage Data In Order No. 693, Paragraph 732, FERC ordered NERC to collect and analyze transmission outage data to inform development of the revised standard. EEI encourages the drafting team and NERC Standards Committee to request that NERC collect and analyze this critically important information. Such analysis provides an important foundation for determining whether the standard can ensure an adequate level of reliability as required by Section 215.Applicability Order No. 693, Paragraph 708, directs NERC to 'develop an acceptable definition that covers facilities that impact reliability but balances extending the applicability of this standard against unreasonably increasing the burden on transmission owners.' In the order, FERC appears to accept the 200-kv threshold, however, continues to ask about these other critical facilities. EEI recommends that the drafting team develop a definition of 'sub- 200kv critical facilities' for use in the standard. Reliance on Reliability Coordinators for developing their own definition raises the likelihood of inconsistent approaches and applications of the term. In addition, the drafting team should consider whether such critical facilities might require expanding applicability to entities other than Transmission Owners. Annual Plan as a Defined Term In order to aid in compliance enforcement and industry compliance, the term 'annual plan' should be a defined term.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. We agree with many of your points. The SDT developed R2 to promote proactive behavior by requiring the recording and documentation of imminent threat procedure implementations. The NERC Transmission Availability Data System is set up to collect the outage data as directed by the FERC. In the revised standard, to address the sub 200 kV facilities to be subject to the standard, the SDT chose the Planning Coordinator (rather than the Reliability Coordinator) for that task. The Planning Coordinator has the wide area view and appropriate time horizon perspective to identify sub 200 kV facilities. The SDT considered the situation where non-TO facilities such as generator “leads” would be subject to this Standard. There is an ongoing discussion within NERC with regard to registration of Generator Owner’s as limited TO’s. Annual plans have relevance within this Standard’s context and are not needed elsewhere. Therefore a glossary definition is not necessary.	
Consolidated Edison Company of New York (CECONY)	CECONY does not feel that, as currently written, the Standard would effectively enhance reliability throughout the industry. We recommend that stricter language be used in the Standard specifically requiring the industry to remove incompatible species on Active ROWs. This should reduce the number of outages resulting from vegetation grow-ins and vegetation fall-ins from inside the Active ROW and help maintain a higher level of reliability. This is currently done at the state level (in NY) and the revised wording in the Federal Standard may help promote consistency industry-wide and avoid confusion. Also, the concept of the Critical Clearance Zone is theoretically strong but it needs to be made simpler for the auditors and field inspectors.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. We agree with many of your points. The SDT developed R2 to promote proactive behavior by requiring the recording and documentation of imminent threat procedure implementations. The NERC Transmission Availability Data System is set up to collect the outage data as directed by the FERC. . In the revised standard, To address the sub 200 kV facilities to be subject to the standard the SDT chose the Planning	

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WECC	Reporting requirements are not identified in the standard. WECC believes that sustained outages caused by vegetation should be reported to the Regional Entity using the existing reporting requirements in FAC-003-1 (Transmission Owners report outages to the Regional Entity). Reports of sustained outages to the Reliability Coordinator should be made for reliability purposes and not compliance purposes. The Reliability Coordinator should not be required to report vegetation outages of individual Transmission Owners to the compliance department.
Response: The SDT thanks you for your comments. The revised Standard reflects changes in reporting requirements.	
Arizona Public Service Company	APS has a comment to NERC on picking the standard drafting team. FAC-003 is a vegetation management standard not an engineering standard. The team members should have been chosen based on managing the vegetation program not because they were engineers. Any standard that is developed should not contain advisory-type language? it should be declarative in tone. For example, in R1.4, the ending clause that begins "and may include actions" should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program. APS supports the development of this white paper as a way to help ensure consistent interpretation of the standard. Perhaps the lack of such a paper in the first version of the standard contributed to the varying interpretations by the auditors. The utilities understand however that this document is not a legal document and is not binding.
Response: The SDT thanks you for your comments. The members of the SDT were selected based on their expertise – the following was taken from the SDT Nomination form: **Candidates should have expertise in one or more of the following areas:** - **Transmission line rights-of-way (ROW) vegetation management or ROW maintenance** - **Transmission line design and ratings** - **Regulatory or legal considerations in ROW maintenance** - **Existing codes and good practices in vegetation management** **Most of the SDT members have expertise in vegetation management.** **The SDT has removed the advisory language in R1.4. The SDT has professional foresters, vegetation managers, system operators and regulators.**	
Baltimore Gas & Electric	The Applicability Section of the Reliability Standards (4.2 Facilities) defines the Transmission Lines (Applicable Lines) that must comply to the reliability standard. This section should clearly state that the scope is limited to the facilities that are Bulk Electric System facilities

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Company	consistent with the Bulk Electric System definition as defined by the Regional Entity. Regarding M5, M6, M7:The intention of these paragraphs is unclear to me as written. At first glance, it appeared that the paragraphs were asking for a negative to be proven, e.g. prove that you didn't have any tree-related outages. Anther possible meaning is that utilities have to justify the cause of any outage that may occur. As such, the burden of proof is on the Transmission Owner to provide evidence that an outage was not caused by trees. If an outage were to occur but the Transmission Owner could not find any evidence of the cause, the wording in these paragraphs suggests that by default, the outages will be classified as tree-related. If these paragraphs are intended to assign an outage cause to an outage that has already occurred, then perhaps they could be reworded to say something to the effect of: "Transmission Owner shall provide results of investigation into all transmission outages?? "If these paragraphs are not intended to assign an outage cause to an outage that already occurred, but to provide a mechanism to report outage performance that is currently covered in M3 and M4 in FAC-003-1, then perhaps they could be reworded to say something to the effect of: "Transmission Owner shall provide documentation of tree-related outage performance on a quarterly basis. Investigation results for unknown outages shall also be provided on a quarterly basis." Or as one last suggestion, the wording could simply be: " The Transmission Owner has evidence that there was a Sustained Tree-related Outage?. Regarding the Tech. Reference, I thought that overall it was helpful and will be valuable to help provide guidance for Transmission Vegetation Management Program development and implementation. The area that covers the Active/Inactive R/W should be more clearly explained and illustrated, particularly with respect to the towers with space for another circuit on one side of the structures.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The old M5, M6, and M7 have changed in a manner that should clarify their interpretation as you requested. The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are now required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. **Reporting requirements are included in the compliance section with this posting.** **The SDT will attempt to incorporate your suggestions on illustrations for double circuits in the white paper with the final posting of this standard.**	
Duke Energy Corporation	FAC-003-1 lacks clarity that is essential for understanding what is necessary for compliance. The proposed FAC-003-2 needs to be simplified to aid with field implementation and compliance interpretation. Currently, it does not provide the clarity and simplification needed by Transmission Owners and regulatory bodies to enhance reliability.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. These changes are directed at the clarity and simplification you requested for effective field implementation and compliance interpretation.	
CenterPoint Energy	The proposed FAC-003-2 has gone FAR beyond what was contemplated by the Commission in FERC Order 693 and equates to a total re-writing of the Standard for no apparent reason. The Commission's determination dealt with the following areas: (1) applicability; (2)

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	inspection cycles; and (3) minimum clearances on National Forest Service lands. For instance in Paragraph 729, the Commission states, "As proposed in the NOPR, the Commission approves Reliability Standard FAC-003-1 with no proposed modification on the issue of clearances. The Commission reaffirms its interpretation that FAC-003-1 requires sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions?." Rewriting the minimum clearances introduced a new set of confusing definitions, and further burdens the Transmission Owners with new documentation requirements with little if any benefit when compared to the Clearance 2 concept in the existing Standard. A preferred approach would have been to incorporate the following few items into the existing Standard: (1) the RC versus the RRO; (2) the designation of a specific inspection frequency; (3) the Gallet equation; and (4) the applicability to National Forest Service lands. We agree that the removal of requirements for quarterly reporting of outages, Clearance 1, and personnel qualifications reduces the burden on the Transmission Owners and does not affect the purpose of the standard to prevent vegetation outages. The Standard could meet its purpose and be streamlined by considering the following changes:1. Delete the new terms and definitions for "Active Transmission Line Right-of-way" and "Critical Clearance Zone" and revert back to a Clearance 2 requirement while replacing the IEEE 516 standard distances with the Gallet equation standard distances.2. Delete R2, M2, R4 and M4 which refer to the "Critical Clearance Zone" and rely on R5, M5, R6, M6, R7, and M7 which refer to the prevention of Sustained Outages.3. Delete R1.5 and M1.5 as a requirement and measure, but footnote the "interim corrective action process" as a best practice as was ANSI A300 in R1.1.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. Items such as the CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. Note that the SAR for this project included a list of items to be addressed in the revised standard – and these items included not only the directives in Order 693, but other issues identified during the initial implementation of the standard and during the refinement of the SAR.	
Entergy Services	Entergy requests that the proposed FAC-003-2 revision continue work on clarifying the above mentioned "Disagree" items and appreciates the consideration of the above comments in the development of the standard. A clear understanding of all standard requirements by the industry is needed to make certain field implementation is achieved and that ultimately we improve system reliability.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. Those changes were made in part for the clarity that you and others requested in order to ensure that practical field implementation may be achieved.	
Alberta Electric System Operator	The AESO is also a signatory to the joint ISO/RTransmission Owner Council Standards Review Committee comments which reflect our comments to the other questions in the Comment Form.
Response: The SDT thanks you for your comments. Please see the SDT's responses to the ISO/RTO SRC comments.	
JEA	M5, 6 and 7 ask the entity to prove the negative. This type of evidence is problematic, and may result in nothing better than the entity

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	making an attestation that the event did not occur, thus this measure is not useful. With well over 100,000 miles of transmission covered by this standard, even six-sigma performance would result in vegetation related issues. It is unreasonable to expect zero-tolerance for vegetation events and unnecessary for the industry (and customers) to expend resources to attempt to meet this level of compliance when the transmission system is planned and operated to handle any single contingency, which means that a vegetation contact should not, in isolation, cause a major problem to the bulk power system. This standard needs work to make it clear, unambiguous, feasible and enforceable.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. **The SDT pursued an approach to develop a metric that would not have a zero-tolerance for outages. Discussion with FERC led the SDT to the conclusion that such an approach would not be acceptable.** **Changes made to the old M5, M6 and M7 in this new draft should alleviate the "prove a negative" dilemma.**	
Independent Electricity System Operator	We recommend removing the Transmission Owner as the one to define a major storm, this task should be left to an applicable regulatory body only, for consistency in assessing such an event. Also, we recommend footnote #5 specify that planned removal of vegetation by the utility is not part of the exceptions, because in our view this activity is a component of the vegetation management program and that outages should be preventable. There is a typo in R6. The numeral "4" should be superscripted.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment **The SDT has reviewed the data on vegetation related outages that TO have reported on the NERC website. There are 223 reports of outages in that data covering the period January 2004 to March 2009. The associated documentation with these events indicate that TO are supplying supportive information to indicate that the level of any disaster exclusion (including major storms) is sufficient to reasonably identify conditions that exceed design criteria. Further specific on the threshold for each disaster (or storm) would not ensure that weather data would be adequate to support each location/situation.** **Random human error in felling trees whether by loggers, homeowners or vegetation removal crews has not been associated with cascading events and remains a valid exclusion. The related safety risks and equipment damages tend to effectively self-control this type of activity.** **The typographical error in what was R6 (now R7) has been corrected.**	
Salt River Project	We question the method used in determining the clearance distances for Vegetation near Transmission Lines. First is the use of the Gallet Equation. Although the Gallet Equation is more definitive than using IEEE 516 as identified in the current standard, we have questions from an engineering prespective as to how and why this method was chosen for vegetation management. It is stated in the Technical Reference paper that the Gallet Equation is a well known method of computing the required strike distance for proper insulation coordination. It is our understanding it's purpose is for designing towers, to define the "tower window" or opening inside of a

Organization	Question 18 Comment
	tower under normal conditions. Because this is not a method designed specifically for vegetation management, what is the basis for applying this to vegetation management? Was there, or could there be testing done? We would find it definitive to substantiate the calculated equation assertions with test data from actual energized flashover distances to vegetation. The testing ought to include dry and misting conditions at 200+ kilovolt levels on a sampling of fresh cut common vegetation types. Reputable EHV testing facilities where such tests can be performed exist within the United States and Canada. Is there additional information to clarify why this method was used to help establish clearance distances for vegetation near transmission lines? Second, it is expected that each utility needs to define their "Critical Clearance Zone". It is outlined in the Technical Reference document how complicated it is to define this clearance area. As the conductor moves throughout its "flight path", the minimum clearance shell surrounding the conductor moves along with it. The shape and size of the Critical Clearance Zone around the conductors is irregular and will change depending on where a conductor segment is located within the span. At mid-span, where the potential for conductor movement is the greatest due to sag and wind deflection, the corresponding Critical Clearance Zone is also the largest and most irregular. With the size, shape, and area of the Critical Clearance Zone dramatically changing as one progresses along a span, identifying the precise location and boundary of the Critical Clearance Zone around the conductor in the field becomes very problematic. There are many variables that are involved at any point along a line and at any given time (loading, operating temperature, wind, maximum design rating, maximum operating loading and so on). Therefore, even if the exact size and shape of the Critical Clearance Zone is known, it becomes nearly impossible to field correlate and accurately "superimpose" the Critical Clearance Zone" around the conductor. Therefore, it seems unreasonable to expect each utility to develop and implement a defensible and auditable clearance zone. We strongly support the development of the Technical Reference document. This would have been helpful if it was available for the first version, as it will help both utilities and auditors. We recommend that this be included in the revised version and subsequent future revisions. Please note that as FAC-003-2 goes through additional revisions prior to finalization, the Technical Reference document needs to be revised to reflect the final revisions prior to implementation.
Response: The SDT thanks you for your comments. The SDT engaged TO personnel who were technical experts with significant experience and credentials in transmission line insulation coordination theory and applications. The purpose of the change to the Gallet derived distances was to provide a set of specific distances that would ensure that flashover would not occur provided those distances were not breeched under expected outdoor operating conditions. These distances are applicable to the wire with respect to structure components, vegetation or any other object at ground potential level. These values have already been proven for dry and wet conditions and need no further testing. **We have made changes in R2 and R4 that should remove the problems you have raised regarding the CCZ and how it is "nearly impossible" to apply under field conditions.**	
Northeast Utilities	In section 4.2.2. the time period for bringing sub 200-kV lines into compliance with the standard states a 12 month period following the designation of the lower voltage lines by the Reliability Coordinator. This can present problems if the RC designates the lines during the course of a plan year, because budgets may not have been established or funded for the additional work. It is suggested that the time period be revised to state, "by the end of the following calendar or budget year after the designation of lower voltage lines", allowing for a full calendar/budget year that can be planned and budgeted to bring lines into compliance.

Organization	Question 18 Comment
	There is concern over the use of the Critical Clearance Zone and making this the "bright line" where encroachment at any time under any conditions is a violation of the standard. The Critical Clearance Zone is a very detailed and calculated zone. It is improbable that an accurate determination of the Critical Clearance Zone could be made in the field. Mere encroachment should not constitute a violation. If the encorachment can be determined and corrected once found - this should be an acceptable practice. It is reasonable for utilities to spend the time, money and manpower to actively manage rights-of-way, and dealing with encroachment issues which can be identified. Many potential encroachments will not be identifiable unless one can accurately identify the Critical Clearance Zone in all cases in all areas at all times. Also, there is some concern over how the requirements are set up for violations of the Critical Clearance Zone and for sustained outages. A sustained outage due to vegetation within the active transmission right-of-way is a violation under R.5, R.6 and R.7. It is also possible that the outage is a violation of the Critical Clearance Zone under R.4. The standard implies that a utility could be assessed multiple violations of the standard for one outage with multiple penalties. Is this the desired intent? Finally, version 1 had clear requirements on what was to be reported, when the reports were required, and who was to submit reports. Is it intended that the standard rely solely on self-reports? Version 2 makes no mention of what is to be reported when a violation occurs, or of any other reports. Is reporting going to be left up to the Regional Entity to establish?
Response: The SDT thanks you for your comments. **The standard was revised to replace the Reliability Coordinator with the Planning Coordinator as the entity responsible for identifying lines sub 200 kV for which there should be a TVMP. By moving to the Planning Coordinator, there should be ample time to address the annual work plan. With its focus on "planning horizon" issues (> 1 year), the PC provides the necessary look-ahead that the RC did not. As soon as a sub-200 kV line is designated as being applicable to this standard, it is understood the subject line could potentially place the grid at risk of instability, separation or cascading. A 12 month period to perform any vegetation maintenance seems reasonable to the SDT.** **Significant changes have been made to the current draft of the Standard based upon substantive industry comment. Items such as the CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. Reporting requirements have been addressed in the compliance section of the revised Standard.**	
Hydro-Quebec Transenergie (HQT)	HQT recommends that the Standard Drafting Team review the compliance and reporting requirements for consistency and adequacy. Applicability 4.2.3 contradict first part of Applicability 4.2.1 and that of former Applicability 4.3
Response: The SDT thanks you for your comments. The SDT reviewed your concern and did not see a contradiction.	
BCTC	Any standard that is developed should not contain advisory-type language—it should be declarative in tone. For example, in R1.4, the ending clause that begins "…and may include actions…" should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program. BCTC supports the development of this white paper as a way to help ensure consistent interpretation of the standard. Perhaps the lack

Organization	Question 18 Comment
	of such a paper in the first version of the standard contributed to the varying interpretations by the auditors. The utilities understand however that this document is not a legal document and is not binding.
Response: The SDT thanks you for your comments. R1.4 has been changed to remove the advisory type language.	

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SC approved SAR for initial posting (January 11, 2007).
2. SAR posted for comment (January 15–February 14, 2007).
3. SAR posted for comment (April 10–May 9, 2007).
4. SC authorized moving the SAR forward to standard development (June 27, 2007).

Proposed Action Plan and Description of Current Draft:

This is the second posting of the proposed revisions to the requirements and measures in the standard. The drafting team added compliance elements to the standard and requests posting for a 45-day comment period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Drafting team considers comments, makes conforming changes, posts for 45-day second comment period.	August 2009
2. Drafting team considers comments, makes conforming changes, posts for 30-day third comment period.	February 2010
3. Drafting team considers comments, makes conforming changes, and requests SC approval to proceed to pre-ballot comment period.	April 2010
4. First ballot of standards.	May 2010
5. Recirculation ballot of standards.	June 2010
6. Board adopts standards.	August 2010

Definitions of Terms Used in Standard+

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Active Transmission Line Right of Way — A strip of land that is occupied by active transmission facilities. This corridor does not include the inactive or unused part of the Right of Way intended for other facilities.

Vegetation Inspection — The systematic examination of vegetation conditions on an Active Transmission Line Right of Way. This inspection may be combined with a general line inspection. The inspection includes the documentation of any vegetation that may pose a threat to reliability prior to the next planned inspection or maintenance work, considering the current location of the conductor and other possible locations of the conductor due to sag and sway for rated conditions.

A. Introduction

1. **Title:** Transmission Vegetation Management Program

2. **Number:** FAC-003-2

3. **Purpose:** To improve the reliability of the electric transmission system by preventing those vegetation related outages that could lead to Cascading.

4. **Applicability:**

   4.1 Functional Entities:

   4.1.1 Transmission Owner

   4.1.2 Planning Coordinator

   4.2 Facilities:

   4.2.1 Transmission lines (“applicable lines”) operated at 200kV or higher, and transmission lines operated below 200kV designated by the Planning Coordinator as being subject to this standard including but not limited to those that cross lands owned by federal1, state, provincial, public, private, or tribal entities.

   4.2.2 Transmission lines operated below 200kV designated by the Planning Coordinator as being subject to this standard become subject to this standard 12 months after the date the Planning Coordinator initially designates the transmission line as being subject to this standard.

   4.2.3 Existing transmission lines operated at 200kV or higher which are newly acquired by a Transmission Owner and were not previously subject to this standard, become subject to this standard 12 months after the acquisition date of the transmission lines.

5. **Effective Dates:**

   In those jurisdictions where regulatory approval is required, the first calendar day of the first calendar quarter one year after applicable regulatory authority approval for all requirements; or, in those jurisdictions where no regulatory approval is required, the first calendar day of the first calendar quarter one year following Board of Trustees adoption.

[1] EPAct 2005 section 1211c: *“Access approvals by Federal agencies”*

B. Requirements

R1. Each Transmission Owner shall have a documented transmission vegetation management program that describes how it conducts work on its Active Transmission Line Rights of Way to prevent Sustained Outages due to vegetation, considering all possible locations the conductor may occupy under the effects of sag and sway throughout its operating range under rated conditions. The transmission vegetation management program shall: *[Violation Risk Factor — Lower][Time Horizon — Long-term planning]*

1.1. Specify the methods that the Transmission Owner may use to control vegetation.[2]

1.2. Specify a Vegetation Inspection frequency of at least once per calendar year that takes into account local[3] and environmental factors.

1.3. Require an annual work plan. An annual work plan shall:

1.3.1. Identify the applicable lines to be maintained.

1.3.2. Identify the work to be performed and methods to be used.

1.3.3. Be flexible to adjust to changing conditions and to findings from Vegetation Inspections. Adjustments to the plan within the year are permissible.

1.3.4. Take into consideration permitting and scheduling requirements from landowners or regulatory authorities.

1.4. Require a process or procedure for response to an imminent threat of a vegetation-related Sustained Outage. The process or procedure shall specify actions which shall include communication of the threat to the responsible control center.

1.5. Specify an interim corrective action process for use when the Transmission Owner is temporarily constrained from performing vegetation maintenance as planned.

1.6. Specify the maintenance strategies used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that Table 1 clearances in Attachment 1 are never violated. The maintenance strategies shall consider the sag and sway of the conductor throughout its operating range under rated conditions.

R2. Each Transmission Owner shall implement its imminent threat process or procedure when the Transmission Owner has actual knowledge of such a threat,

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[2] ANSI A300, Tree Care Operations — Tree, Shrub, and Other Woody Plant Maintenance — Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

[3] Local factors include items such as treatment cycle, extent and type of treatment, and their relationship to the normal growth rate.

obtained through normal operating practices. *[Violation Risk Factor — Medium][Time Horizon — Real Time]*

R3. Each Transmission Owner shall conduct Vegetation Inspections of all applicable lines (as measured in line miles) in accordance with the frequency specified in its transmission vegetation management program, unless constrained by natural disasters[4]. When constrained by a natural disaster, the Transmission Owner shall conduct the Vegetation Inspection(s) within six months or a period agreed to by its Regional Entity, whichever is greater. *[Violation Risk Factor — Medium][Time Horizon — Operations Planning]*

R4. Each Transmission Owner shall prevent encroachment of vegetation into the Minimum Vegetation Clearance Distances (MVCD) listed in FAC-003-2 - Attachment 1 for its applicable lines as observed in real-time operating between no-load and their Rating, with the following exceptions: *[Violation Risk Factor — Medium][Time Horizon — Real Time]*

- Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from natural disasters.[4]
- Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from human or animal activity.[5]
- Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from falling vegetation.

R5. Each Transmission Owner shall prevent Sustained Outages[6] of applicable lines that are identified as an element of an Interconnection Reliability Operating Limit (IROL) (or Major WECC Transfer Path) due to vegetation growing into a conductor operating between no-load and its Rating, with the following exceptions: *[Violation Risk Factor — High][Time Horizon — Real Time]*

- Sustained Outages of applicable lines that result from natural disasters.[4]
- Sustained Outages of applicable lines that result from human or animal activity.[5]

R6. Each Transmission Owner shall prevent Sustained Outages[6] of applicable lines that are not an element of an IROL (or major WECC Transfer Path) due to vegetation growing into a conductor operating between no-load and its Rating, with the following exceptions: *[Violation Risk Factor — Medium][Time Horizon — Real Time]*

- Sustained Outages of applicable lines that result from natural disasters.[4]

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[4] Examples include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods.

[5] Examples include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation.

[6] Multiple Sustained Outages on an individual line, if caused by the same vegetation, shall be considered as one outage regardless of the actual number of outages within a 24-hour period.

- Sustained Outages of applicable lines that result from human or animal activity.[5]

R7. Each Transmission Owner shall prevent Sustained Outages[6] of applicable lines due to the blowing together of vegetation and a conductor within an Active Transmission Line Right of Way (operating within design blow-out conditions) with the following exception: *[Violation Risk Factor — Medium][Time Horizon — Real Time]*

- Sustained Outages of applicable lines that result from natural disasters[4] or wind-blown debris.

R8. Each Transmission Owner shall prevent Sustained Outages[6] of applicable lines due to vegetation falling into a conductor from within an Active Transmission Line Right of Way with the following exceptions: *[Violation Risk Factor — Medium] [Time Horizon — Real Time]*

- Sustained Outages of applicable lines that result from natural disasters[4] or wind-blown debris.
- Sustained Outages of applicable lines that result from human or animal activity.[5]

R9. Each Transmission Owner shall implement its annual work plan for vegetation management to accomplish the purpose of this standard. *[Violation Risk Factor — Medium] [Time Horizon — Operations Planning]*

R10. Each Planning Coordinator shall prepare and review annually, a list of lines that are operated below 200kV, if any, which are subject to this standard. Each Planning Coordinator shall consult with its Transmission Owner(s) and neighboring Planning Coordinators to obtain input to develop the list. *[Violation Risk Factor — Lower] [Time Horizon — Long-term Planning]*

R11. Each Planning Coordinator shall develop and document its method for assessing the reliability significance of sub-200kV transmission lines whose loss would place the grid at an unacceptable risk of instability, separation, or cascading failures. *[Violation Risk Factor — Lower] [Time Horizon — Long-term Planning]*

C. Measures

M1. The Transmission Owner has a documented transmission vegetation management program (paper or electronic copy of dated, current, in force document with specified elements) that describes how it conducts work on its Active Transmission Line Rights of Way to prevent Sustained Outages due to vegetation, considering all possible locations the conductor may occupy under the effects of sag and sway throughout its operating range under rated conditions. (R1)

1.1. The Transmission Owner's transmission vegetation management program documentation specifies the methods that the Transmission Owner may use to control vegetation.

1.2. The Transmission Owner's transmission vegetation management program documentation specifies a Vegetation Inspection frequency of at least once per calendar year that takes into account local and environmental factors.

1.3. The Transmission Owner's transmission vegetation management program contains an annual work plan which:

1.3.1. Identifies the applicable lines to be maintained

1.3.2. Identifies the work to be performed and the methods used

1.3.3. Shows flexibility to adjust to changing conditions and to findings from Vegetation Inspections

1.3.4. Considers permitting and scheduling requirements from landowners or regulatory authorities.

1.4. The Transmission Owner's transmission vegetation management program documentation specifies an imminent threat process or procedure for responding to imminent threats of a vegetation-related Sustained Outage including communication of the threat to the responsible control center.

1.5. The Transmission Owner's transmission vegetation management program documentation specifies the interim corrective action process for use when the Transmission Owner is temporarily constrained from performing vegetation maintenance as planned.

1.6. The Transmission Owner's transmission vegetation management program documentation specifies the maintenance strategies used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that Table 1 clearances in Attachment 1 are never violated. The maintenance strategies consider the sag and sway of the conductor throughout its operating range under rated conditions.

M2. The Transmission Owner has evidence of the implementation of its vegetation imminent threat process or procedure showing what was done with dates and activities accomplished. (R2)

M3. The Transmission Owner has evidence that it conducted Vegetation Inspections in accordance with Requirement R3.

M4. The Transmission Owner has evidence from inspections that indicate there was no vegetation encroachment into the Minimum Vegetation Clearance Distances listed in FAC-003-2-Attachment 1 for its applicable lines as observed in real-time operating between no-load and their Rating, considering exceptions. (R4)

M5. The Transmission Owner's self-certification reports are adequate evidence of no Sustained Outage of any applicable line that is identified as an element of an IROL (or Major WECC Transfer Path) due to vegetation growing into a conductor operating between no-load and its Rating. (R5)

M6. The Transmission Owner's self-certification reports are adequate evidence of no Sustained Outage of any applicable line that is not identified as an element of an IROL (or Major WECC Transfer Path) due to vegetation growing into a conductor operating between no-load and its Rating. (R6)

M7. The Transmission Owner's self-certification reports are adequate evidence of no Sustained Outage of any applicable line due to the blowing together of vegetation and a conductor within the Active Transmission Line Right of Way. (R7)

M8. The Transmission Owner's self-certification reports are adequate evidence of no Sustained Outage of any applicable line due to vegetation falling into a conductor from within the Active Transmission Line Right of Way. (R8)

M9. The Transmission Owner has evidence that it is implementing, or has implemented, its annual work plan. An example of evidence is a paper or electronic copy of work plan and work records. (R9)

M10. The Planning Coordinator has evidence that it consulted with its Transmission Owner(s) and neighboring Planning Coordinator(s), prepared and reviewed annually a list of designated sub-200kV transmission lines, if any, which are subject to this standard. (R10)

M11. The Planning Coordinator has documented evidence such as planning study criteria or other analysis used to develop its method for assessing the reliability significance of sub-200kV lines whose loss would place the grid at an unacceptable risk of instability, separation, or cascading failures. (R11)

D. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not Applicable

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

Periodic Data Submittals for Sustained Outages caused by vegetation

1.4 Data Retention

The Transmission Owner and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Owner shall retain as evidence of Requirements 1 through 9, Measures 1 through 9 for three years.
- The Planning Coordinator shall retain evidence of Requirement 10 and 11, Measure 10 and 11 for one year.

If a Transmission Owner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5 Additional Compliance Information

The Transmission Owner shall report quarterly to its Regional Entity, or the Regional Entity's designee, Sustained Outages of its transmission lines determined by the Transmission Owner to have been caused by vegetation, including the following:

The name of the circuit(s), the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner, and Sustained Outage Category based on the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines that are identified as an element of an IROL (or Major WECC Transfer Path) by vegetation inside and/or outside of the Active Transmission Line ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines but are not identified as an element of an IROL (or Major WECC Transfer Path) by vegetation inside and/or outside of the Active Transmission Line ROW;
- Category 2 — Fall-ins: Sustained Outages caused by vegetation falling into lines from within the Active Transmission Line ROW;
- Category[7] 4 — Blowing together: Sustained Outages caused by vegetation and lines blowing together from within the Active Transmission Line ROW.

[7] Category 3 reporting is eliminated.

Violation Severity Levels

R#	Violation Risk Factor	Violation Severity Level			
		Lower	Moderate	High	Severe
R1	Lower	The Transmission Owner has a transmission vegetation management program, but the transmission vegetation management program is missing one of the following: Requirement 1, Part 1.1, or Requirement 1, Part 1.2	The Transmission Owner has a transmission vegetation management program, but the transmission vegetation management program is missing either Requirement R1, Part 1.5 or Requirement R1, Part 1.1 and Part 1.2	The Transmission Owner has a transmission vegetation management program, but the transmission vegetation management program is missing up to two of the following parts of Requirement R1: Parts 1.3, 1.4 and 1.6	The Transmission Owner does not have transmission vegetation management program or the transmission vegetation management program is missing all of the following Parts of Requirement R1: Parts 1.3, 1.4 and 1.6
R2	Medium				The Transmission Owner did not implement its imminent threat process or procedure when the Transmission Owner had actual knowledge of such a threat, obtained through normal operating practices
R3	Medium	The Transmission Owner inspected greater than 75% but less than 100% of the total line miles specified by its transmission vegetation management program.	The Transmission Owner inspected greater than 50% but less than or equal to 75% of the total line miles specified by its transmission vegetation management program.	The Transmission Owner inspected greater than 25% but less than or equal to 50% of the total line miles specified by its transmission vegetation management program.	The Transmission Owner inspected less than or equal to 25% of the total line miles specified by its transmission vegetation management program.
R4	Medium				The Transmission Owner has failed to prevent vegetation from encroaching into the minimum vegetation clearance distance.

R#	Violation Risk Factor	Violation Severity Level			
		Lower	Moderate	High	Severe
R5	High				The Transmission Owner incurred a Sustained Outage due to vegetation growing into an applicable transmission line that is identified as an element of an IROL (or Major WECC Transfer Path).
R6	Medium				The Transmission Owner incurred a Sustained Outage due to vegetation growing into an applicable transmission line that is not identified as an element of an IROL (or Major WECC Transfer Path).
R7	Medium				The Transmission Owner incurred a Sustained Outage due to the blowing together of vegetation and a conductor of an applicable transmission within an Active Transmission Line Right of Way.
R8	Medium				The Transmission Owner incurred a Sustained Outage due to vegetation falling into an applicable transmission from within an Active Transmission Line Right of Way.
R9	Medium	The Transmission Owner failed to implement 5% or less of its annual work	The Transmission Owner failed to implement more than 5% but less than or	The Transmission Owner failed to implement more than 10% but less than or equal to	The Transmission Owner failed to implement more than 15% of its annual work

R#	Violation Risk Factor	Violation Severity Level			
		Lower	Moderate	High	Severe
		plan.	equal to 10% of its annual work plan.	15% of its annual work plan.	plan.
R10	Lower	The Planning Coordinator failed to consult with one of its Transmission Owners or one of its adjacent Planning Coordinators in developing its list of designated sub-200kV transmission lines, if any, that are subject to this standard..	The Planning Coordinator failed to consult with more than one of its Transmission Owners or more than one of its adjacent Planning Coordinators in developing its list of designated sub-200kV transmission lines, if any, that are subject to this standard.	The Planning Coordinator has not annually reviewed its list of designated sub-200kV transmission lines, if any, that are subject to this standard.	The Planning Coordinator has not prepared a list of designated sub-200kV transmission lines, if any, that are subject to this standard.
R11	Lower	The Planning Coordinator has not documented its method for assessing the reliability significance of sub-200kV lines.	The Planning Coordinator has not considered lines whose loss would place the grid at an unacceptable risk of instability, separation, or cascading failures in developing its method for assessing the reliability significance of sub-200kV lines.	NA	The Planning Coordinator has not developed a method for assessing the reliability significance of sub-200kV lines.

Regional Variances

None identified.

Associated Technical Reference Documents

FAC-003 Reference — Transmission Vegetation Management — White Paper.

Version History

Version	Date	Action	Change Tracking
1	TBA	1. Added “Standard Development Roadmap.” 2. Changed “60” to “Sixty” in section A, 5.2. 3. Added “Proposed Effective Date: April 7, 2006” to footer. 4. Added “Draft 3: November 17, 2005” to footer.	01/20/06
1	April 4, 2007	Regulatory Approval — Effective Date	New
2		Complete revision	

FAC-003-2-Attachment 1

TABLE 1 — Minimum Vegetation Clearance Distances (MVCD)

For **Alternating Current** Voltages

(AC) Nominal System Voltage (kV)	(AC) Maximum System Voltage (kV)	MVCD feet (meters) sea level	MVCD feet (meters) 3,000ft (914.4m)	MVCD feet (meters) 4,000ft (1219.2m)	MVCD feet (meters) 5,000ft (1524m)	MVCD feet (meters) 6,000ft (1828.8m)	MVCD feet (meters) 7,000ft (2133.6m)	MVCD feet (meters) 8,000ft (2438.4m)	MVCD feet (meters) 9,000ft (2743.2m)	MVCD feet (meters) 10,000ft (3048m)	MVCD feet (meters) 11,000ft (3352.8m)
765	800	8.06ft (2.46m)	8.89ft (2.71m)	9.17ft (2.80m)	9.45ft (2.88m)	9.73ft (2.97m)	10.01ft (3.05m)	10.29ft (3.14m)	10.57ft (3.22m)	10.85ft (3.31m)	11.13ft (3.39m)
500	550	5.06ft (1.54m)	5.66ft (1.73m)	5.86ft (1.79m)	6.07ft (1.85m)	6.28ft (1.91m)	6.49ft (1.98m)	6.7ft (2.04m)	6.92ft (2.11m)	7.13ft (2.17m)	7.35ft (2.24m)
345	362	3.12ft (0.95m)	3.53ft (1.08m)	3.67ft (1.12m)	3.82ft (1.16m)	3.97ft (1.21m)	4.12ft (1.26m)	4.27ft (1.30m)	4.43ft (1.35m)	4.58ft (1.40m)	4.74ft (1.44m)
230	242	2.97ft (0.91m)	3.36ft (1.02m)	3.49ft (1.06m)	3.63ft (1.11m)	3.78ft (1.15m)	3.92ft (1.19m)	4.07ft (1.24m)	4.22ft (1.29m)	4.37ft (1.33m)	4.53ft (1.38m)
161*	169	2ft (0.61m)	2.28ft (0.69m)	2.38ft (0.73m)	2.48ft (0.76m)	2.58ft (0.79m)	2.69ft (0.82m)	2.8ft (0.85m)	2.91ft (0.89m)	3.03ft (0.92m)	3.14ft (0.96m)
138*	145	1.7ft (0.52m)	1.94ft (0.59m)	2.03ft (0.62m)	2.12ft (0.65m)	2.21ft (0.67m)	2.3ft (0.70m)	2.4ft (0.73m)	2.49ft (0.76m)	2.59ft (0.79m)	2.7ft (0.82m)
115*	121	1.41ft (0.43m)	1.61ft (0.49m)	1.68ft (0.51m)	1.75ft (0.53m)	1.83ft (0.56m)	1.91ft (0.58m)	1.99ft (0.61m)	2.07ft (0.63m)	2.16ft (0.66m)	2.25ft (0.69m)
88*	100	1.15ft (0.35m)	1.32ft (0.40m)	1.38ft (0.42m)	1.44ft (0.44m)	1.5ft (0.46m)	1.57ft (0.48m)	1.64ft (0.50m)	1.71ft (0.52m)	1.78ft (0.54m)	1.86ft (0.57m)
69*	72	0.82ft (0.25m)	0.94ft (0.29m)	0.99ft (0.30m)	1.03ft (0.31m)	1.08ft (0.33m)	1.13ft (0.34m)	1.18ft (0.36m)	1.23ft (0.37m)	1.28ft (0.39m)	1.34ft (0.41m)

*As designated by the Planning Coordinator

TABLE 1 (CONT.) — Minimum Vegetation Clearance Distances (MVCD) For **Direct Current** Voltages

(DC) Nominal Pole to Ground Voltage (kV)	MVCD feet (meters) sea level	MVCD feet (meters) 3,000ft (914.4m) Alt.	MVCD feet (meters) 4,000ft (1219.2m) Alt.	MVCD feet (meters) 5,000ft (1524m) Alt.	MVCD feet (meters) 6,000ft (1828.8m) Alt.	MVCD feet (meters) 7,000ft (2133.6m) Alt.	MVCD feet (meters) (8,000ft (2438.4m) Alt.	MVCD feet (meters) 9,000ft (2743.2m) Alt.	MVCD feet (meters) 10,000ft (3048m) Alt.	MVCD feet (meters) 11,000ft (3352.8m) Alt.
±750	13.92ft (4.24m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.9ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.07ft (3.07m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	(13.54ft 4.13m)
±500	7.89ft (2.40m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	4.78ft (1.46m)	5.35ft (1.63m)	5.55ft (1.69m)	5.75ft (1.75m)	5.95ft (1.81m)	6.15ft (1.87m)	6.36ft (1.94m)	6.57ft (2.00m)	6.77ft (2.06m)	6.98ft (2.13m)
±250	3.43ft (1.05m)	4.02ft (1.23m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5ft (1.52m)	5.17ft (1.58m)

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SC approved SAR for initial posting (January 11, 2007).
2. SAR posted for comment (January 15–February 14, 2007).
3. SAR posted for comment (April 10–May 9, 2007).
4. SC authorized moving the SAR forward to standard development (June 27, 2007).

Proposed Action Plan and Description of Current Draft:

This is the second posting of the proposed revisions to the requirements and measures in the standard. The drafting team added compliance elements to the standard and requests posting for a 45-day comment period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Drafting team considers comments, makes conforming changes, posts for 45-day second comment period.	August 2009
2. Drafting team considers comments, makes conforming changes, posts for 30-day third comment period.	February 2010
3. Drafting team considers comments, makes conforming changes, and requests SC approval to proceed to pre-ballot comment period.	April 2010
4. First ballot of standards.	May 2010
5. Recirculation ballot of standards.	June 2010
6. Board adopts standards.	August 2010

Definitions of Terms Used in Standard+

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Active Transmission Line Right of Way — A strip of land that is occupied by active transmission facilities. This corridor does not include the inactive or unused part of the Right of Way intended for other facilities.

~~**Critical Clearance Zone** — The area mapped by the radial distance around a conductor specified in Table I of Attachment 1 to reliability standard FAC-003-2 — Transmission~~

Vegetation ~~Management Program when the conductor is energized and operating between no-load and its Rating, including the design blowout, however, the zone shall not extend beyond the limits~~**Inspection —** The systematic examination of ~~the~~vegetation conditions on an Active Transmission Line Right of Way. This inspection may be combined with a general line inspection. The inspection includes the documentation of any vegetation that may pose a threat to reliability prior to the next planned inspection or maintenance work, considering the current location of the conductor and other possible locations of the conductor due to sag and sway for rated conditions.

A. Introduction

1. **Title:** Transmission Vegetation Management Program

2. **Number:** FAC-003-2

3. **Purpose:** To improve the reliability of the ~~Bulk Electric System~~electric transmission system by preventing those vegetation related outages that could lead to Cascading.

4. **Applicability:**

   Functional Entities:

   - Transmission Owner
   - ~~Reliability~~Planning Coordinator

   Facilities:

   - Transmission lines (“applicable lines”) operated at 200kV or higher, and transmission lines operated below 200kV designated by the ~~Reliability~~Planning Coordinator as being subject to this standard including but not limited to those that cross lands owned by federal1, state, provincial, public, private, or tribal entities.
   - Transmission lines operated below 200kV designated by the ~~Reliability~~Planning Coordinator as being subject to this standard become subject to this standard 12 months after the date the ~~Reliability~~Planning Coordinator initially designates the transmission line as being subject to this standard.
   - Existing transmission lines operated at 200kV or higher which are newly acquired by a Transmission Owner and were not previously subject to this standard, become subject to this standard 12 months after the acquisition date of the transmission lines~~s~~.

5. **Effective Dates:**

   In those jurisdictions where regulatory approval is required, the first calendar day of the first calendar quarter one year after applicable regulatory authority approval for all requirements; or, in those jurisdictions where no regulatory approval is required, the first calendar day of the first calendar quarter one year following Board of Trustees adoption.

[1] EPAct 2005 section 1211c: “*Access approvals by Federal agencies*~~”~~ ”

B. Requirements

R1. Each Transmission Owner shall have a documented transmission vegetation management program ~~designed to control vegetation~~ that describes how it conducts work on its Active Transmission ~~Lines'~~ Line Rights of Way to prevent Sustained Outages due to vegetation, considering all possible locations the conductor may occupy under the effects of sag and sway throughout its operating range under rated conditions. The transmission vegetation management program shall: *[Violation Risk Factor – Lower][Time Horizon – Long-term planning]*

1.1. Specify the ~~methodologies~~ methods that the Transmission Owner ~~uses~~ may use to control vegetation.[2]

1.2. Specify a ~~vegetation inspection~~Vegetation Inspection frequency of at least once per calendar year that takes into account local[3] and environmental factors.

1.3. Require an annual work plan ~~that identifies~~. An annual work plan shall:

1.3.1. Identify the applicable lines to be maintained ~~and associated~~

1.3.2. Identify the work to be performed ~~during the year. It shall~~ and methods to be used

1.3.3. Be flexible to adjust to changing conditions and to findings from ~~vegetation inspections.~~ Vegetation Inspections. Adjustments to the plan within the year are permissible. ~~The plan shall~~

1.3.4. Take into consideration permitting and scheduling requirements from landowners or regulatory authorities. ~~It shall support the objectives of the transmission vegetation management program and use the methodologies outlined in the transmission vegetation management program.~~

1.4. Require a process or procedure for response to an imminent ~~threats~~ threat of a vegetation~~-~~-related Sustained Outage. The process or procedure shall specify actions which shall include ~~immediate~~ communication of the threat to the ~~Transmission Operator, and may include actions such as a temporary reduction in line Rating, switching lines out of service, or other actions.~~responsible control center.

1.5. Specify an interim corrective action process for use when the Transmission Owner is temporarily constrained from performing vegetation maintenance as planned.

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2 ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

3 Local factors include items such as treatment cycle, extent and type of treatment, and their relationship to the normal growth rate.

1.6. Specify the maintenance strategies used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that Table 1 clearances in Attachment 1 are never violated. The maintenance strategies shall consider the sag and sway of the conductor throughout its operating range under rated conditions.

R2. Each Transmission Owner shall implement its imminent threat process or procedure when the Transmission Owner has actual knowledge of such a threat, obtained through normal operating practices ~~or notification from others, that the Critical Clearance Zone is approached by vegetation to prevent an encroachment of the Critical Clearance Zone.~~. *[Violation Risk Factor – Medium][Time Horizon – Real Time]*

R3. Each Transmission Owner shall conduct ~~inspections~~Vegetation Inspections of all applicable lines (as measured in line miles) in accordance with the frequency specified in its transmission vegetation management program~~.~~, unless constrained by natural disasters[4]. When constrained by a natural disaster, the Transmission Owner shall conduct the Vegetation Inspection(s) within six months or a period agreed to by its Regional Entity, whichever is greater. *[Violation Risk Factor – Medium][Time Horizon – Operations Planning]*

R4. Each Transmission Owner shall prevent encroachment ~~within~~of vegetation into the ~~Critical~~Minimum Vegetation Clearance ~~Zone of~~ Distances (MVCD) listed in FAC-003-2 - Attachment 1 for its applicable lines as observed in real-time operating between no-load and their Rating, with the following exceptions: *[Violation Risk Factor – Medium][Time Horizon – Real Time]*

- ~~Encroachments of~~Encroachment into the ~~Critical~~MVCD listed in FAC-003-2-Attachment 1 resulting from natural disasters.[4]
- ~~Encroachments of~~ Encroachment into the ~~Critical~~MVCD listed in FAC-003-2-Attachment 1 resulting from human or animal activity.[5]
- Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from falling vegetation.

R5. Each Transmission Owner shall prevent Sustained Outages[6] of applicable lines~~[7]~~ that are identified as an element of an Interconnection Reliability Operating Limit (IROL) (or Major WECC Transfer Path) due to vegetation growing into a conductor operating between no-load and its Rating, with the following exceptions: *[Violation Risk Factor – High][Time Horizon – Real Time]*

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[4] Examples include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods.

[5] Examples include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation.

[6] Multiple Sustained Outages on an individual line, if caused by the same vegetation, shall be considered as one outage regardless of the actual number of outages within a 24-hour period.

- Sustained Outages of applicable lines that result from natural disasters.[4]
- Sustained Outages of applicable lines that result from human or animal activity.[5]

R6. Each Transmission Owner shall prevent Sustained Outages[6] of applicable ~~lines[6]~~ lines that are not an element of an IROL (or major WECC Transfer Path) due to vegetation growing into a conductor operating between no-load and its Rating, with the following exceptions: *[Violation Risk Factor – Medium][Time Horizon – Real Time]*

- Sustained Outages of applicable lines that result from natural disasters.[4]
- Sustained Outages of applicable lines that result from human or animal activity.[5]

R7. Each Transmission Owner shall prevent Sustained Outages[6] of applicable lines due to the blowing together of vegetation and a conductor within an Active Transmission Line Right of Way (operating within design blow-out conditions) with the following exception: *[Violation Risk Factor – Medium][Time Horizon – Real Time]*

- Sustained Outages of applicable lines that result from ~~sustained winds or gusts due to natural disasters.4~~natural disasters[4] or wind-blown debris.

R8. Each Transmission Owner shall prevent Sustained Outages[6] of applicable ~~lines[6]~~ lines due to vegetation falling into a conductor from within an Active Transmission Line Right of Way with the following exceptions: *[Violation Risk Factor – Medium] [Time Horizon – Real Time]*

- Sustained Outages of applicable lines that result from natural disasters~~.~~[4] or wind-blown debris.
- Sustained Outages of applicable lines that result from human or animal activity.[5]

R9. Each Transmission Owner shall implement its annual work plan for vegetation management to accomplish the purpose of this standard~~ within the extent of its easement and/or legal rights.~~. *[Violation Risk Factor – Medium] [Time Horizon – Operations Planning]*

R10. Each ~~Reliability~~Planning Coordinator ~~in consultation with its Transmission Owner(s) and neighboring Reliability Coordinator(s)~~ shall ~~jointly~~ prepare and ~~keep current,~~ review annually, a list of ~~designated applicable~~ lines that are operated below ~~200~~200kV, if any, which are subject to this standard. Each Planning Coordinator shall consult with its Transmission Owner(s) and neighboring Planning Coordinators to obtain input to develop the list. *[Violation Risk Factor – Lower] [Time Horizon – Long-term Planning]*

~~**R10.**~~ Each ~~Reliability~~Planning Coordinator shall develop and document its method for assessing the reliability significance of sub-200kV ~~lines considering all of the following:~~

~~**R10.1** Transmission lines whose loss would result in the exceedance of an Interconnection Reliability Operating Limit (IROL)~~

R11. ~~**R10.2**~~ ~~Transmission~~ transmission lines whose loss would place the grid at an unacceptable risk of instability, separation, or cascading failures. *[Violation Risk Factor – Lower] [Time Horizon – Long-term Planning]*

C. Measures

M1. The Transmission Owner has a documented transmission vegetation management program ~~designed to control~~ (paper or electronic copy of dated, current, in force document with specified elements) that describes how it conducts work on its Active Transmission Line Rights of Way to prevent Sustained Outages due to vegetation ~~on the Active Transmission Line Right of Way.~~, considering all possible locations the conductor may occupy under the effects of sag and sway throughout its operating range under rated conditions. (R1)

1.1. The Transmission Owner's transmission vegetation management program documentation specifies the ~~methodologies~~methods that the Transmission Owner ~~uses~~may use to control vegetation.

1.2. The Transmission Owner's transmission vegetation management program documentation specifies a ~~vegetation inspection~~Vegetation Inspection frequency of at least once per calendar year that takes into account local and environmental factors. ~~This inspection frequency shall be at least once per calendar year.~~

1.3. The Transmission Owner's transmission vegetation management program ~~requires~~contains an annual work plan ~~and it~~ which:

1.3.1. Identifies the applicable lines to be maintained ~~and related vegetation management work to be performed during the calendar year while taking into consideration~~

1.3.2. Identifies the work to be performed and the methods used

1.3.3. Shows flexibility to adjust to changing conditions and to findings from Vegetation Inspections

1.3.4. Considers permitting and scheduling requirements from landowners or regulatory authorities.

1.4. The Transmission Owner's transmission vegetation management program ~~requires~~ documentation specifies an imminent threat process or procedure for responding to imminent threats of a vegetation-related Sustained Outage including ~~immediate~~ communication of the threat to the ~~Transmission Operator, and may include a temporary reduction in line Rating, switching lines out of service, and/or other actions that may be taken until the threat is relieved~~responsible control center.

1.5. The Transmission Owner's transmission vegetation management ~~program~~program documentation specifies the interim corrective action process for use when the Transmission Owner is temporarily constrained from performing vegetation maintenance as planned.

1.6. The Transmission Owner's transmission vegetation management program documentation specifies the maintenance strategies used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that Table 1 clearances in Attachment 1 are never violated. The maintenance strategies consider the sag and sway of the conductor throughout its operating range under rated conditions.

M2. The Transmission Owner has evidence ~~that it implemented its~~ of the implementation of its vegetation imminent threat process or procedure ~~when it obtained knowledge that the Critical Clearance Zone~~showing what was ~~approached by vegetation.~~done with dates and activities accomplished. (R2)

M3. The Transmission Owner has evidence that it conducted ~~vegetation inspections of all applicable transmission lines~~Vegetation Inspections in accordance with ~~the frequency specified in its transmission vegetation management program. (~~Requirement R3~~)~~.

M4. ~~The Transmission Owner has evidence such as inspection records, imminent threat reports or quality assurance reports, demonstrating there were no vegetation encroachments into the Critical Clearance Zone.~~The Transmission Owner has evidence from inspections that indicate there was no vegetation encroachment into the Minimum Vegetation Clearance Distances listed in FAC-003-2-Attachment 1 for its applicable lines as observed in real-time operating between no-load and their Rating, considering exceptions. (R4)

M5. The Transmission ~~Owner has~~Owner's self-certification reports are adequate evidence ~~that there was not a~~ of no Sustained Outage of ~~an~~ any applicable line that is identified as an element of an IROL (or Major WECC Transfer Path) due to vegetation growing into a conductor operating between no-load and its Rating. (R5)

M6. The Transmission Owner's self-certification reports are adequate evidence of no Sustained Outage of any applicable line that is not identified as an element of an IROL (or Major WECC Transfer Path) due to vegetation growing into a conductor operating between no-load and its Rating. (~~R5~~R6)

M7. The Transmission ~~Owner has~~Owner's self-certification reports are adequate evidence ~~that there was not a~~of no Sustained Outage of ~~an~~ any applicable line due to the blowing together of vegetation and a conductor within the Active Transmission Line Right of Way. (~~R6~~R7)

M8. The Transmission ~~Owner has~~Owner's self-certification reports are adequate evidence ~~that there was not a~~of no Sustained Outage of ~~an~~any applicable line due to vegetation falling into a conductor from within the Active Transmission Line Right of Way. (~~R7~~R8)

M9. The Transmission Owner has evidence that it is implementing, or has implemented, its annual work plan. ~~(R8~~An example of evidence is a paper or electronic copy of work plan and work records. (R9)

M10. The ~~Reliability~~Planning Coordinator has evidence that it consulted with its Transmission Owner(s) and ~~adjacent Reliability~~neighboring Planning Coordinator(s), prepared and ~~kept current~~reviewed annually a list of designated sub-200kV transmission lines, if any, which are subject to this standard. (~~R9~~R10)

M11. The ~~Reliability~~Planning Coordinator has documented evidence ~~that it has defined its methods~~such as planning study criteria or other analysis used to develop its method for assessing the reliability significance of sub-200kV lines ~~and has developed selection criteria for listing any sub-200kV lines. (R10~~whose loss would place the grid at an unacceptable risk of instability, separation, or cascading failures. (R11)

D. Compliance

All compliance information is new and shown without "track changes" for ease in reading

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

Regional Entity

1.2 Compliance Monitoring Period and Reset Timeframe

Not Applicable

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

Periodic Data Submittals for Sustained Outages caused by vegetation

1.4 Data Retention

The Transmission Owner and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Owner shall retain as evidence of Requirements 1 through 9, Measures 1 through 9 for three years.
- The Planning Coordinator shall retain evidence of Requirement 10 and 11, Measure 10 and 11 for one year.

If a Transmission Owner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5 Additional Compliance Information

The Transmission Owner shall report quarterly to its Regional Entity, or the Regional Entity's designee, Sustained Outages of its transmission lines determined by the Transmission Owner to have been caused by vegetation, including the following:

The name of the circuit(s), the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner, and Sustained Outage Category based on the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines that are identified as an element of an IROL (or Major WECC Transfer Path) by vegetation inside and/or outside of the Active Transmission Line ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines but are not identified as an element of an IROL (or Major WECC Transfer Path) by vegetation inside and/or outside of the Active Transmission Line ROW;
- Category 2 — Fall-ins: Sustained Outages caused by vegetation falling into lines from within the Active Transmission Line ROW;
- Category[8] 4 — Blowing together: Sustained Outages caused by vegetation and lines blowing together from within the Active Transmission Line ROW.

[8] Category 3 reporting is eliminated.

Violation Severity Levels

R#	Violation Risk Factor	Violation Severity Level			
		Lower	Moderate	High	Severe
R1	Lower	The Transmission Owner has a transmission vegetation management program, but the transmission vegetation management program is missing one of the following: Requirement 1, Part 1.1, or Requirement 1, Part 1.2	The Transmission Owner has a transmission vegetation management program, but the transmission vegetation management program is missing either Requirement R1, Part 1.5 or Requirement R1, Part 1.1 and Part 1.2	The Transmission Owner has a transmission vegetation management program, but the transmission vegetation management program is missing up to two of the following parts of Requirement R1: Parts 1.3, 1.4 and 1.6	The Transmission Owner does not have transmission vegetation management program or the transmission vegetation management program is missing all of the following Parts of Requirement R1: Parts 1.3, 1.4 and 1.6
R2	Medium				The Transmission Owner did not implement its imminent threat process or procedure when the Transmission Owner had actual knowledge of such a threat, obtained through normal operating practices
R3	Medium	The Transmission Owner inspected greater than 75% but less than 100% of the total line miles specified by its transmission vegetation management program.	The Transmission Owner inspected greater than 50% but less than or equal to 75% of the total line miles specified by its transmission vegetation management program.	The Transmission Owner inspected greater than 25% but less than or equal to 50% of the total line miles specified by its transmission vegetation management program.	The Transmission Owner inspected less than or equal to 25% of the total line miles specified by its transmission vegetation management program.
R4	Medium				The Transmission Owner has failed to prevent

R#	Violation Risk Factor	Violation Severity Level			
		Lower	Moderate	High	Severe
					vegetation from encroaching into the minimum vegetation clearance distance.
R5	High				The Transmission Owner incurred a Sustained Outage due to vegetation growing into an applicable transmission line that is identified as an element of an IROL (or Major WECC Transfer Path).
R6	Medium				The Transmission Owner incurred a Sustained Outage due to vegetation growing into an applicable transmission line that is not identified as an element of an IROL (or Major WECC Transfer Path).
R7	Medium				The Transmission Owner incurred a Sustained Outage due to the blowing together of vegetation and a conductor of an applicable transmission within an Active Transmission Line Right of Way.
R8	Medium				The Transmission Owner incurred a Sustained Outage

R#	Violation Risk Factor	Violation Severity Level			
		Lower	Moderate	High	Severe
					due to vegetation falling into an applicable transmission from within an Active Transmission Line Right of Way.
R9	Medium	The Transmission Owner failed to implement 5% or less of its annual work plan.	The Transmission Owner failed to implement more than 5% but less than or equal to 10% of its annual work plan.	The Transmission Owner failed to implement more than 10% but less than or equal to 15% of its annual work plan.	The Transmission Owner failed to implement more than 15% of its annual work plan.
R10	Lower	The Planning Coordinator failed to consult with one of its Transmission Owners or one of its adjacent Planning Coordinators in developing its list of designated sub-200kV transmission lines, if any, that are subject to this standard..	The Planning Coordinator failed to consult with more than one of its Transmission Owners or more than one of its adjacent Planning Coordinators in developing its list of designated sub-200kV transmission lines, if any, that are subject to this standard.	The Planning Coordinator has not annually reviewed its list of designated sub-200kV transmission lines, if any, that are subject to this standard.	The Planning Coordinator has not prepared a list of designated sub-200kV transmission lines, if any, that are subject to this standard.
R11	Lower	The Planning Coordinator has not documented its method for assessing the reliability significance of sub-200kV lines.	The Planning Coordinator has not considered lines whose loss would place the grid at an unacceptable risk of instability, separation, or cascading failures in developing its method for assessing the reliability significance of sub-200kV lines.	NA	The Planning Coordinator has not developed a method for assessing the reliability significance of sub-200kV lines.

Regional Variances

None identified.

Associated Technical Reference Documents

FAC-003 Reference — Transmission Vegetation Management — White Paper.

Version History

Version	Date	Action	Change Tracking
1	TBA	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	01/20/06
1	April 4, 2007	Regulatory Approval — Effective Date	New

2		Complete revision	

FAC-003-2-Attachment 1

~~The Critical Clearance Zone is the area mapped by the radial distance around a conductor specified in~~ TABLE ~~I below when the conductor is energized and operating between no-load and its Rating, including the design blow-out, however, the zone shall not extend beyond the limits of the Active Transmission Line Right of Way.~~

~~TABLE I~~1 — Minimum Vegetation Clearance Distances (MVCD)

For **Alternating Current** Voltages

~~(AC) Nominal System Voltage (kV)~~	~~(AC) Maximum System Voltage (kV)~~	~~D feet (meters) sea level~~	- ~~D feet (meters) 3,000ft (914.4m)~~	- ~~D feet (meters) 4,000ft (1219.2m)~~	- ~~D feet (meters) 5,000ft (1524m)~~	- ~~D feet (meters) 6,000ft (1828.8m)~~
~~765~~	~~800~~	~~8.06ft (2.46m)~~	~~8.89ft (2.71m)~~	~~9.17ft (2.80m)~~	~~9.45ft (2.88m)~~	~~9.73ft (2.97m)~~
~~500~~	~~550~~	~~5.06ft (1.54m)~~	~~5.66ft (1.73m)~~	~~5.86ft (1.79m)~~	~~6.07ft (1.85m)~~	~~6.28ft (1.91m)~~
~~345~~	~~362~~	~~3.12ft (0.95m)~~	~~3.53ft (1.08m)~~	~~3.67ft (1.12m)~~	~~3.82ft (1.16m)~~	~~3.97ft (1.21m)~~
~~230~~	~~242~~	~~2.97ft (0.91m)~~	~~3.36ft (1.02m)~~	~~3.49ft (1.06m)~~	~~3.63ft (1.11m)~~	~~3.78ft (1.15m)~~
~~161*~~	~~169~~	~~2ft (0.61m)~~	~~2.28ft (0.69m)~~	~~2.38ft (0.73m)~~	~~2.48ft (0.76m)~~	~~2.58ft (0.79m)~~
~~138*~~	~~145~~	~~1.7ft (0.52m)~~	~~1.94ft (0.59m)~~	~~2.03ft (0.62m)~~	~~2.12ft (0.65m)~~	~~2.21ft (0.67m)~~
~~115*~~	~~121~~	~~1.41ft (0.43m)~~	~~1.61ft (0.49m)~~	~~1.68ft (0.51m)~~	~~1.75ft (0.53m)~~	~~1.83ft (0.56m)~~
~~88*~~	~~100~~	~~1.15ft (0.35m)~~	~~1.32ft (0.40m)~~	~~1.38ft (0.42m)~~	~~1.44ft (0.44m)~~	~~1.5ft (0.46m)~~

~~69*~~	~~72~~	~~0.82ft (0.25m)~~	~~0.94ft (0.29m)~~	~~0.99ft (0.30m)~~	~~1.03ft (0.31m)~~	~~1.08ft (0.33m)~~

(AC) Nominal System Voltage (kV)	(AC) Maximum System Voltage (kV)	MVCD feet (meters) sea level	MVCD feet (meters) 3,000ft (914.4m)	MVCD feet (meters) 4,000ft (1219.2m)	MVCD feet (meters) 5,000ft (1524m)	MVCD feet (meters) 6,000ft (1828.8m)	MVCD feet (meters) 7,000ft (2133.6m)	MVCD feet (meters) 8,000ft (2438.4m)	MVCD feet (meters) 9,000ft (2743.2m)	MVCD feet (meters) 10,000ft (3048m)	MVCD feet (meters) 11,000ft (3352.8m)
765	800	8.06ft (2.46m)	8.89ft (2.71m)	9.17ft (2.80m)	9.45ft (2.88m)	9.73ft (2.97m)	10.01ft (3.05m)	10.29ft (3.14m)	10.57ft (3.22m)	10.85ft (3.31m)	11.13ft (3.39m)
500	550	5.06ft (1.54m)	5.66ft (1.73m)	5.86ft (1.79m)	6.07ft (1.85m)	6.28ft (1.91m)	6.49ft (1.98m)	6.7ft (2.04m)	6.92ft (2.11m)	7.13ft (2.17m)	7.35ft (2.24m)
345	362	3.12ft (0.95m)	3.53ft (1.08m)	3.67ft (1.12m)	3.82ft (1.16m)	3.97ft (1.21m)	4.12ft (1.26m)	4.27ft (1.30m)	4.43ft (1.35m)	4.58ft (1.40m)	4.74ft (1.44m)
230	242	2.97ft (0.91m)	3.36ft (1.02m)	3.49ft (1.06m)	3.63ft (1.11m)	3.78ft (1.15m)	3.92ft (1.19m)	4.07ft (1.24m)	4.22ft (1.29m)	4.37ft (1.33m)	4.53ft (1.38m)
161*	169	2ft (0.61m)	2.28ft (0.69m)	2.38ft (0.73m)	2.48ft (0.76m)	2.58ft (0.79m)	2.69ft (0.82m)	2.8ft (0.85m)	2.91ft (0.89m)	3.03ft (0.92m)	3.14ft (0.96m)
138*	145	1.7ft (0.52m)	1.94ft (0.59m)	2.03ft (0.62m)	2.12ft (0.65m)	2.21ft (0.67m)	2.3ft (0.70m)	2.4ft (0.73m)	2.49ft (0.76m)	2.59ft (0.79m)	2.7ft (0.82m)
115*	121	1.41ft (0.43m)	1.61ft (0.49m)	1.68ft (0.51m)	1.75ft (0.53m)	1.83ft (0.56m)	1.91ft (0.58m)	1.99ft (0.61m)	2.07ft (0.63m)	2.16ft (0.66m)	2.25ft (0.69m)
88*	100	1.15ft (0.35m)	1.32ft (0.40m)	1.38ft (0.42m)	1.44ft (0.44m)	1.5ft (0.46m)	1.57ft (0.48m)	1.64ft (0.50m)	1.71ft (0.52m)	1.78ft (0.54m)	1.86ft (0.57m)
69*	72	0.82ft (0.25m)	0.94ft (0.29m)	0.99ft (0.30m)	1.03ft (0.31m)	1.08ft (0.33m)	1.13ft (0.34m)	1.18ft (0.36m)	1.23ft (0.37m)	1.28ft (0.39m)	1.34ft (0.41m)

*As designated by the ~~Reliability~~Planning Coordinator

TABLE ~~I~~1 (CONT.) — Minimum Vegetation Clearance Distances (MVCD)~~s (D)~~

~~For Alternating Current Voltages~~

~~(AC) Nominal System Voltage (kV)~~	~~(AC) Maximum System Voltage (kV)~~	~~D feet (meters) 7,000ft (2133.6m)~~	~~D feet (meters) 8,000ft (2438.4m)~~	~~D feet (meters) 9,000ft (2743.2m)~~	~~D feet (meters) 10,000ft (3048m)~~	~~D feet (meters) 11,000ft (3352.8m)~~
~~765~~	~~800~~	~~10.01ft (3.05m)~~	~~10.29ft (3.14m)~~	~~10.57ft (3.22m)~~	~~10.85ft (3.31m)~~	~~11.13ft (3.39m)~~
~~500~~	~~550~~	~~6.49ft (1.98m)~~	~~6.7ft (2.04m)~~	~~6.92ft (2.11m)~~	~~7.13ft (2.17m)~~	~~7.35ft (2.24m)~~
~~345~~	~~362~~	~~4.12ft (1.26m)~~	~~4.27ft (1.30m)~~	~~4.43ft (1.35m)~~	~~4.58ft (1.40m)~~	~~4.74ft (1.44m)~~
~~230~~	~~242~~	~~3.92ft (1.19m)~~	~~4.07ft (1.24m)~~	~~4.22ft (1.29m)~~	~~4.37ft (1.33m)~~	~~4.53ft (1.38m)~~
~~161*~~	~~169~~	~~2.69ft (0.82m)~~	~~2.8ft (0.85m)~~	~~2.91ft (0.89m)~~	~~3.03ft (0.92m)~~	~~3.14ft (0.96m)~~
~~138*~~	~~145~~	~~2.3ft (0.70m)~~	~~2.4ft (0.73m)~~	~~2.49ft (0.76m)~~	~~2.59ft (0.79m)~~	~~2.7ft (0.82m)~~
~~115*~~	~~121~~	~~1.91ft (0.58m)~~	~~1.99ft (0.61m)~~	~~2.07ft (0.63m)~~	~~2.16ft (0.66m)~~	~~2.25ft (0.69m)~~
~~88*~~	~~100~~	~~1.57ft (0.48m)~~	~~1.64ft (0.50m)~~	~~1.71ft (0.52m)~~	~~1.78ft (0.54m)~~	~~1.86ft (0.57m)~~
~~69*~~	~~72~~	~~1.13ft (0.34m)~~	~~1.18ft (0.36m)~~	~~1.23ft (0.37m)~~	~~1.28ft (0.39m)~~	~~1.34ft (0.41m)~~

~~*As designated by the Reliability Coordinator~~

~~TABLE I — Minimum Vegetation Clearance Distances (MVCD)~~
For **Direct Current** Voltages

~~(DC) Pole to Pole Nominal Voltage (kV)~~	~~D feet (meters) sea level~~	~~D feet (meters) 3,000ft (914.4m) Alt.~~	~~D feet (meters) 4,000ft (1219.2m) Alt.~~	~~D feet (meters) 5,000ft (1524m) Alt.~~	~~D feet (meters) 6,000ft (1828.8m) Alt.~~
~~1500~~	~~13.92ft (4.24m)~~	~~15.07ft (4.59m)~~	~~15.45ft (4.71m)~~	~~15.82ft (4.82m)~~	~~16.2ft (4.94m)~~
~~1200~~	~~10.07ft (3.07m)~~	~~11.04ft (3.36m)~~	~~11.35ft (3.46m)~~	~~11.66ft (3.55m)~~	~~11.98ft (3.65m)~~
~~1000~~	~~7.89ft (2.40m)~~	~~8.71ft (2.65m)~~	~~8.99ft (2.74m)~~	~~9.25ft (2.82m)~~	~~9.55ft (2.91m)~~
~~800~~	~~4.78ft (1.46m)~~	~~5.35ft (1.63m)~~	~~5.55ft (1.69m)~~	~~5.75ft (1.75m)~~	~~5.95ft (1.81m)~~

~~500~~	~~3.43ft (1.05m)~~	~~4.02ft (1.23m)~~	~~4.02ft (1.23m)~~	~~4.18ft (1.27m)~~	~~4.34ft (1.32m)~~
	-	-	-	-	-

~~Pole to Pole Nominal Voltage (kV)~~	~~D feet (meters) 7,000ft (2133.6m) Alt.~~ -	~~D feet (meters) (8,000ft (2438.4m) Alt.~~ -	~~D feet (meters) 9,000ft (2743.2m) Alt.~~ -	~~D feet (meters) 10,000ft (3048m) Alt.~~ -	~~D feet (meters) 11,000ft (3352.8m) Alt.~~ -
~~1500~~	~~16.55ft (5.04m)~~	~~16.9ft (5.15m)~~	~~17.27ft (5.26m)~~	~~17.62ft (5.37m)~~	~~17.97ft (5.48m)~~
~~1200~~	~~12.3ft (3.75m)~~	~~12.62ft (3.85m)~~	~~12.92ft (3.94m)~~	~~13.24ft (4.04m)~~	~~(13.54ft 4.13m)~~
~~1000~~	~~9.82ft (2.99m)~~	~~10.1ft (3.08m)~~	~~10.38ft (3.16m)~~	~~10.65ft (3.25m)~~	~~10.92ft (3.33m)~~
~~800~~	~~6.15ft (1.87m)~~	~~6.36ft (1.94m)~~	~~6.57ft (2.00m)~~	~~6.77ft (2.06m)~~	~~6.98ft (2.13m)~~
~~500~~	~~4.5ft (1.37m)~~	~~4.66ft (1.42m)~~	~~4.83ft (1.47m)~~	~~5ft (1.52m)~~	~~5.17ft (1.58m)~~

(DC) Nominal Pole to Ground Voltage (kV)	MVCD feet (meters) sea level	MVCD feet (meters) 3,000ft (914.4m) Alt.	MVCD feet (meters) 4,000ft (1219.2m) Alt.	MVCD feet (meters) 5,000ft (1524m) Alt.	MVCD feet (meters) 6,000ft (1828.8m) Alt.	MVCD feet (meters) 7,000ft (2133.6m) Alt.	MVCD feet (meters) (8,000ft (2438.4m) Alt.	MVCD feet (meters) 9,000ft (2743.2m) Alt.	MVCD feet (meters) 10,000ft (3048m) Alt.	MVCD feet (meters) 11,000ft (3352.8m) Alt.
±750	13.92ft (4.24m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.9ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.07ft (3.07m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	(13.54ft 4.13m)
±500	7.89ft (2.40m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)

±400	4.78ft (1.46m)	5.35ft (1.63m)	5.55ft (1.69m)	5.75ft (1.75m)	5.95ft (1.81m)	6.15ft (1.87m)	6.36ft (1.94m)	6.57ft (2.00m)	6.77ft (2.06m)	6.98ft (2.13m)
±250	3.43ft (1.05m)	4.02ft (1.23m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5ft (1.52m)	5.17ft (1.58m)

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

FAC-003-1 Mapping to Proposed NERC Reliability Standard FAC-003-2

Standard FAC-003-1 NERC Board Approved	Comment	Proposed Standard FAC-003-2
0. Definitions	**0.** The definition of Active Transmission Line Right of Way was added in response to FERC 693 and industry comments. The glossary definition of Vegetation Inspection was changed in response to industry comments.	**Active Transmission Line Right of Way** — A strip of land that is occupied by active transmission facilities. This corridor does not include the inactive Right of Way or unused part of the Right of Way intended for other facilities. **Vegetation Inspection** — The systematic examination of vegetation conditions on an Active Transmission Line Right of Way. This inspection may be combined with a general line inspection. The inspection includes the documentation of any vegetation that may pose a threat to reliability prior to the next planned inspection or maintenance work, considering the current location of the conductor and other possible locations of the conductor due to sag and sway for rated conditions.
1. Title: Transmission Vegetation Management Program	**1. Title:** No Change (N/C)	**1. Title:** Transmission Vegetation Management Program
3. Purpose: To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation related outages of the transmission systems to the respective Regional Reliability Organizations (RRO) and the North American Electric Reliability Council (NERC).	**3. Purpose:** Changed to a shorter more concise purpose statement. The various explanatory objectives are now addressed within the standard’s requirements.	**3. Purpose:** To improve the reliability of the electric transmission system by preventing those vegetation related outages that could lead to Cascading.
4. Applicability:	**4. Applicability:**	**4. Applicability:**

4.1. Transmission Owner	4.1 N/C	**4.1. Functional Entities** 4.1.1. Transmission Owner 4.1.2. Planning Coordinator
4.2. Regional Reliability Organization 4.3. This standard shall apply to all transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RRO as critical to the reliability of the electric system in the region.	4.2 Removed Regional Reliability Organization in response to FERC Order 693 and later added Planning Coordinator in lieu of Reliability Coordinator in response to industry comments to the October 27, 2008 comments. 4.3 (Note that the version 1 section 4.3 is now covered in version 2 section 4.2) 4.2.1 Added reference to lines that cross lands owned by federal, state, provincial, public, private, or tribal entities. Changed RRO to Planning Coordinator 4.2.2. Added criterion to identify the time frame provided to manage sub 200kV lines to the standard after the Planning Coordinator has determined that they are subject to the standard. 4.2.3. Added criterion to specify when a newly acquired line above 200kV will become	**4.2. Facilities** 4.2.1. Transmission lines ("applicable lines") operated at 200kV or higher, and transmission lines operated below 200kV designated by the Planning Coordinator as being subject to this standard including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities. 4.2.2. Transmission lines operated below 200kV designated by the Planning Coordinator as being subject to this standard become subject to this standard 12 months after the date the Planning Coordinator initially designates the transmission line as being subject to this standard. 4.2.3. Existing transmission line(s) operated at 200kV or higher that are newly acquired by a Transmission Owner and were not previously subject to this standard, become subject to this standard 12 months after the acquisition date of the transmission line(s).

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies"*

	subject to the standard.	
Effective Dates: **5.1** One calendar year from the date of adoption by the NERC Board of Trustees for Requirement 1 and 2. **5.2** Sixty calendar days from the date of adoption by the NERC Board of Trustees for the Requirements 3 and 4.	**Effective Dates:** Consistency with standards approval process for a standard revision.	**5. Effective Dates:** In those jurisdictions where regulatory approval is required, the first calendar day of the first calendar quarter one year after applicable regulatory authority approval for all requirements; or, in those jurisdictions where no regulatory approval is required, the first calendar day of the first calendar quarter one year following Board of Trustees adoption.
R1. The Transmission Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the Transmission Owner's objectives, practices, approved procedures, and work specifications[1]. **R1.1.** The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the Transmission Owner's transmission lines. **R1.2** The Transmission Owner, in the TVMP, shall identify and document the clearances between vegetation and any overhead, ungrounded supply concoctors taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway.	**R1.** Changed R1 to be a TVMP "documentation" requirement not an implementation requirement. Items changed or modified were removed Clearance 1 (which was a fill in the blank) Clearance 2 was replaced by MVCD (to find a more acceptable alternative to MAID), added the frequency of at least once per calendar year to Vegetation Inspections, moved imminent threat action from the original R1.5 to the new requirement R2, removed personnel qualifications (they were fill-in-the-blank), replaced the term "mitigation measures " with "interim corrective action process" to avoid conflict with NERC's use of the term "imminent threat:, specified that maintenance strategies to achieve clearance must consider the sag and sway under all rated conditions, and clarified that this applies on the active transmission line ROW. Added requirements for the documentation of an annual work plan	**R1.** Each Transmission Owner shall have a documented transmission vegetation management program that describes how it conducts work on its Active Transmission Line Rights of Way to prevent Sustained Outages due to vegetation, considering all possible locations the conductor may occupy under the effects of sag and sway throughout its operating range under rated conditions. The transmission vegetation management program shall: **1.1.** Specify the methods that the Transmission Owner may use to control vegetation. **1.2.** Specify a Vegetation Inspection frequency of at least once per calendar year that takes into account local and environmental factors. **1.3.** Require an annual work plan. An annual work plan shall: **1.3.1.** Identify the applicable lines to be maintained **1.3.2.** Identify the work to be performed and methods to be used **1.3.3.** Be flexible to adjust to changing conditions and to findings from Vegetation Inspections. Adjustments to the plan within the year are permissible. **1.3.4.** Take into consideration permitting and scheduling requirements from landowners or

Specifically, the Transmission Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors. **R1.2.1.** Clearance 1 — The Transmission Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner plans to return for future **R1.2.2.** Clearance 2 — The Transmission Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These Transmission Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap. **R1.2.2.1** Where transmission system transient		regulatory authorities. **1.4.** Require a process or procedure for response to an imminent threat of a vegetation-related Sustained Outage. The process or procedure shall specify actions which shall include communication of the threat to the responsible control center. **1.5.** Specify an interim corrective action process for use when the Transmission Owner is temporarily constrained from performing vegetation maintenance as planned. **1.6.** Specify the maintenance strategies used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that Table 1 clearances in Attachment 1 are never violated. The maintenance strategies shall consider the sag and sway of the conductor throughout its operating range under rated conditions.

overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied. **R1.2.2.2** Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied **R1.3.** All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner, to perform their duties. **R1.4.** Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner is restricted from attaining the clearances specified in Requirement 1.2.1. **R1.5.** Each Transmission Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage.		
R2. The Transmission Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical	**R2.** Reduced the verbiage, moved the "create" function and other documentation activities/actions into new R1.section 1.3, and moved the implementation function into R9.	**R9.** Each Transmission Owner shall implement its annual work plan for vegetation management to accomplish the purpose of this standard.

clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.		
R3. The Transmission Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission Owner to have been caused by vegetation.	Reporting requirements are now located in the compliance section, A**dditional Compliance Information,** as required by "NERC Standard format", specifically, reporting outages in and of itself does not improve reliability.	**Additional Compliance Information** The Transmission Owner shall report quarterly to its Regional Entity, or the Regional Entity's designee, Sustained Outages of its transmission lines determined by the Transmission Owner to have been caused by vegetation, including the following: The name of the circuit(s), the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner, and Sustained Outage Category based on the following: • Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines that are identified as an element of an IROL (or Major WECC Transfer Path) by vegetation inside and/or outside of the Active Transmission Line ROW; • Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines but are not identified

		as an element of an IROL (or Major WECC Transfer Path) by vegetation inside and/or outside of the Active Transmission Line ROW; • Category 2 — Fall-ins: Sustained Outages caused by vegetation falling into lines from within the Active Transmission Line ROW; • Category[2] 4 — Blowing together: Sustained Outages caused by vegetation and lines blowing together from within the Active Transmission Line ROW.
R4. The RRO shall report the outage information provided to it by Transmission Owner's, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the RRO as a result of any of the reported outages.	This is now covered in the **Additional Compliance Information** as is appropriate for all reporting issues.	
NOTE: Below are new requirement in Version 2 that were not in Version 1 and were not mapped above.		
	The new Version 2 of the standard now has a separate requirement for documenting and implementing the imminent threat.	**R2.** Each Transmission Owner shall implement its imminent threat procedure when the Transmission Owner has actual knowledge of such a threat, obtained through normal operating practices
	The new Version 2 of the standard now has a separate requirement for documenting and implementing the Vegetation Inspections.	**R3.** Each Transmission Owner shall conduct Vegetation Inspections of all applicable lines (as measured in line miles) in accordance with the frequency specified in its transmission vegetation management program, unless constrained by natural disasters[5]. When constrained by a natural disaster, the Transmission Owner shall conduct the

[2] Category 3 reporting is eliminated.

		Vegetation Inspection(s) within 6 months or a period agreed to by its Regional Entity, whichever is greater
	The new Version 2 utilizes MVCD, a technically justifiable separation distance at which flashover will not occur, and applies it to real time observations to provide the clarity needed for field applications. The combination of choosing an effective maintenance strategy (R1 section 1.6), effective inspections (R3), and annual work performance (R9), will ensure a high level of reliability while imminent threat implementation (R2) and MVCD findings (R4) will provide the feedback to the Transmission Owner necessary to in make improvements in the overall maintenance of vegetation.	**R4.** Each Transmission Owner shall prevent encroachment of vegetation into the Minimum Vegetation Clearance Distances ("MVCD") listed in FAC-003-2-Attachment 1 for its applicable lines as observed in real-time operating between no-load and their Rating with the following exceptions:
	R5, R6, R7 and R8 explicitly state that sustained outages from vegetation are violations of this standard. This removes the implicit interpretation that is currently in Version 1. R5 and its companion R6 apply to grow-ins. R5 applies to the most significant circuits and is separated from R6 to allow application of the most appropriate VRF. R7 addresses blowing together and R8 addresses fall-ins.	**R5.** Each Transmission Owner shall prevent Sustained Outages of applicable lines that are identified as an element of an Interconnection Reliability Operating Limit (or Major WECC Transfer Path in the Western Interconnection) due to vegetation growing into a conductor operating between no-load and its Rating with the following exceptions: • Sustained Outages of applicable lines that result from natural disasters. • Sustained Outages of applicable lines that result from human or animal activity. **R6.** Each Transmission Owner shall prevent Sustained Outages of applicable lines that are not an element of an Interconnection Reliability Operating Limit (or Major WECC Transfer Path in the Western

		Interconnection) due to vegetation growing into a conductor operating between no-load and its Rating with the following exceptions: • Sustained Outages of applicable lines that result from natural disasters. • Sustained Outages of applicable lines that result from human or animal activity. **R7.** Each Transmission Owner shall prevent Sustained Outages of applicable lines due to the blowing together of vegetation and a conductor within an Active Transmission Line Right of Way (operating within design blow-out conditions) with the following exception: • Sustained Outages of applicable lines that result from natural disasters or wind-blown debris. **R8.** Each Transmission Owner shall prevent Sustained Outages of applicable lines due to vegetation falling into a conductor from within an Active Transmission Line Right of Way with the following exceptions: • Sustained Outages of applicable lines that result from natural disasters or wind-blown debris. • Sustained Outages of applicable lines that result from human or animal activity.
	Two separate and distinct elements in this standard were created to remove confusion about the difference between the TVMP (a document) and the annual work plan. The annual work plan documentation is in R1	**R9**. Each Transmission Owner shall implement its annual work plan for vegetation management to accomplish the purpose of this standard.

	section 1.3 and the implementation of the annual work plan is in R9,	
	In response to FERC order 693 and industry comment, the PC has been assigned as the appropriate functional entity to prepare the list of applicable lines below 200 kV.	**R10**. Each Planning Coordinator shall prepare and keep current, a list of lines that are operated below 200 kV, if any, which are subject to this standard. Each Planning Coordinator shall consult with its Transmission Owner(s) and neighboring Planning Coordinators to obtain input to develop the list.
	This requirement captures the methodology and the parameters to be used by each PC to assess the significance of sub 200 kV lines.	**R11.** Each Planning Coordinator shall develop and document its method for assessing the reliability significance of sub-200kV transmission lines whose loss would place the grid at an unacceptable risk of instability, separation, or cascading failures.

Unofficial Comment Form for Transmission Vegetation Management Standard FAC-003-2 (Project 2007-07)

Please **DO NOT** use this comment form. Please use the electronic comment form located at the link below to submit comments on the proposed standard. Comments must be submitted by **October 24, 2009**. If you have questions please contact Harry Tom at harry.tom@nerc.net.

http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

Opening Remarks:
The SDT appreciates the valuable responses provided by the industry and other stakeholders on this Standard revision. We have worked diligently, utilizing those comments and directives in FERC Order 693 to improve this revision.

Given the importance and complexity of this standard, the SDT felt it was appropriate to develop and provide a comprehensive Technical Reference Document (White Paper) to assist in the interpretation and application of this standard. This companion document is included in this posting of FAC-003-2.

We are optimistic that this Standard fully satisfies stakeholder concerns and FERC Order 693 and believe this version will be ready for balloting after this comment period.

Background Information:
The Vegetation Management Standard Drafting Team (SDT) prepared a proposed revision of FAC-003-1 in accordance with the scope as contained in the Standard Authorization Request (SAR). The SAR includes addressing FERC directives in Order 693. These included:

- Removal of 'fill in the blank' components where the Transmission Owner determines the requirement with no limits or direction. Examples include Clearance 1 and "personnel requirements" in version 1.
- Removal of references to the Regional Reliability Organization (RRO) and replacement with the correct designation of Regional Entity (RE).
- Application of new NERC Drafting Team Guidelines (DTG) to the standard. Examples include the replacement of the current compliance section with Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) as referenced in the Sanction Guidelines. Additionally, documentation and implementation elements are separated into different requirements in the proposed standard as required by the DTG.
- Address the applicability and appropriateness of IEEE 516 in determining clearance distances.
- Address applicability of this standard to sub 200kV lines that could place the grid at an unacceptable risk of instability, separation, or cascading failures.
- Address a minimum vegetation inspection frequency that accounts for local factors.
- Address applicability to federal lands.

The initial proposed revision was posted for industry comment during a public comment period from October 27, 2008 to November 25, 2008. The SDT received comments from 66 separate entities on the initial posting of this proposed standard revision. The completed

Consideration of Comments document spans 279 pages making it one of the largest comment documents for any of the NERC draft standards. There were 17 specific questions and a summary question in the posting.

After careful consideration of FERC Order 693 and all comments from the stakeholders, the Standards Drafting Team (SDT) made revisions to the proposed second in order to make it stronger, clearer and more practical for field implementation. These revisions are fully articulated in the mapping document and should be reviewed by the reader. The SDT also developed a Technical Reference Document (White Paper) to clarify the intent and purpose of each requirement found in FAC-003-2. Many of the significant revisions are, however, highlighted in the following:

The key difference between the current standard and this posting is the requirement that certain vegetation outages are violations of the standard (R5, R6, R7 and R8). These requirements, in a clear and unambiguous manner, address prevention of Sustained Outages due to vegetation.

Key differences between first posting and second posting of proposed FAC-003 -2 include:

- Replaced the Critical Clearance Zone (CCZ) concept found in R4 with a practical field measurement to address commenter's concerns.
- Eliminated the CCZ as the trigger of imminent threat in R2 to address commenters' concerns.
- Added a new part to Requirement R1 - TVMP (1.6) to address commenters' concerns regarding the elimination of Clearance 1. This change requires that the TO account for anticipated conductor movement.
- Developed VRFs and VSLs consistent with the NERC Drafting Team Guidelines.
- Created a second grow-in outage requirement to allow for different VRF levels based on the actual criticality of the line.

The SDT believes that this posting is an improvement over both the FAC 003-1 and the October 27, 2008 posting of FAC 003-2. The following illustrates examples of these improvements.

1. The purpose statement was shortened to be in line with the Drafting Team Guidelines for a more concise purpose statement. The various explanatory objectives in the current standard's Purpose statement are now addressed within the body of the requirements of this second revision.
2. Revised the purpose statement in response to comments about the use of the term Bulk Electric System.
3. The TVMP Requirement found in R1 was re-written to clarify that the objective of the TVMP is to improve reliability by preventing Sustained Outages due to vegetation.
4. Requirement R1, Part 1.6 now requires that the TO effectively describe the strategies used to prevent tree and conductor conflicts, replacing "Clearance 1".
5. Requirement R4 replaces the CCZ concept with a practical "real time" method of observing/measuring vegetation that could cause spark-over.
6. Requirement R2 eliminates the CCZ trigger for the Imminent Threat Process in favor of a more practical field implementation strategy.

7. Defined Vegetation Inspection as a NERC Glossary term. This definition recognizes that vegetation inspections can be performed concurrently with other transmission line inspections.
8. Defined Active Transmission Line Right-of-Way as NERC Glossary term. This limits applicability of the requirements to the portion of the ROW with active transmission facilities.
9. Established a minimum inspection frequency of one calendar year to address FERC concerns about inspection cycles. This also includes a provision to address impact of natural disasters on schedule attainment.
10. Clarified Applicability section to include all types of land ownerships to address FERC concerns identified in Order 693.
11. Established clear process and responsibility to identify and designate sub 200kV lines which will be subject to the provisions of this standard.
12. Developed VRFs in accordance with the Drafting Team Guidelines to better reflect impact/risk to the reliability of the grid.
13. Developed separate requirements for documentation and implementation of the Imminent Threat Process, Vegetation Inspections, and the Annual Work Plan in accordance with the Drafting Team Guidelines.
14. Replaced Clearance 2 with Minimum Vegetation Clearance Distance (MVCD) based on the Gallet equation. This removes the ambiguity about hypothetical versus real-time clearance while still accounting for conductor movement in R1, Part 1.6.
15. Replaced the Reliability Coordinator (RC) with the Planning Coordinator (PC) as the appropriate entity to designate applicable sub 200kV lines.
16. Clarified Interim Corrective Action Plan as "temporary" in nature when the TO is constrained from getting adequate clearance. The Interim Corrective Action Plan also replaces the term Mitigation Plan avoiding conflicts with the Compliance term "Mitigation Plan."
17. Eliminated the reporting requirement for Category 3 (fall-in from outside the ROW) outages.
18. Assigned new Sustained Outage reporting categories (1A, 1B, 2 and 4) which will allow tracking and trending to use historical outages.

Analysis of Industry Comments:
Disagreements were high for questions 1, 7, 11, and 15, with values of 52%, 47%, 57% and 94% respectively. Those disagreements related to the use of the term "Bulk Electric System" in the purpose statement, the identification of actions required of the Transmission Operator when implementing the imminent threat procedure in Requirement R1.4, the use of "approaching" the calculated boundary of the Critical Clearance Zone as the threshold for implementation of the imminent threat procedure in requirement R2, and the use of the calculated boundary of the Critical Clearance Zone as a surface for determining clearance violations in R4. The comments contained numerous suggestions for changes to address the disagreements. The other questions were given mostly agreeable remarks; however some changes were made based on those comments.

The SDT has posted its response to the comments submitted in response to the last draft of this standard. The team updated its Technical Reference to align with the changes made to the proposed standard, updated the "mapping" document, and added an implementation plan. Please review these documents and then answer the following questions.

***Please use the electronic comment form to submit your final responses to NERC.**

1. As stated in the background information above, in response to industry comments, the Requirement for documentation of a TVMP (the new R1) is revised. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

   ☐ Agree

   ☐ Disagree

   Comments:

2. As stated in the background information above, in response to industry comments, the Requirement for implementation of Imminent Threat process/procedure (the new R2) is revised. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

   ☐ Agree

   ☐ Disagree

   Comments:

3. As stated in the background information above, in response to industry comments, the Requirement for conducting Vegetation Inspections (the new R3) is revised. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

   ☐ Agree

   ☐ Disagree

   Comments:

4. As stated in the background information above, in response to industry comments, the Requirement for preventing vegetation encroachments (the new R4) is revised. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

   ☐ Agree

   ☐ Disagree

   Comments:

5. As stated in the background information above, in response to industry comments, the Requirement for preventing Sustained Outages due to grow-ins on IROL or Major WECC Transfer Paths (the new R5) is developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

   ☐ Agree

☐ Disagree

Comments:

6. As stated in the background information above, in response to industry comments, the Requirement for preventing Sustained Outages due to grow-ins on non-IROL or Major WECC Transfer Paths (the new R6) is developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

☐ Agree

☐ Disagree

Comments:

7. As stated in the background information above, in response to industry comments, the Requirement for preventing Sustained Outages due to blowing together of vegetation and transmission line conductors (the new R7) is developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

☐ Agree

☐ Disagree

Comments:

8. As stated in the background information above, in response to industry comments, the Requirement for preventing Sustained Outages due to fall-ins of vegetation (the new R8) is developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

☐ Agree

☐ Disagree

Comments:

9. As stated in the background information above, in response to industry comments, the Requirement for implementation of annual work plan (the new R9) is developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

☐ Agree

☐ Disagree

Comments:

10. As stated in the background information above, in response to industry comments, the Requirement for the preparation of list for sub 200kV transmission lines by the

Planning Coordinator (the new R10) is developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

☐ Agree

☐ Disagree

Comments:

11. As stated in the background information above, in response to industry comments, the Requirement for the Planning Coordinator to document method for identification of applicable sub-200kV transmission lines (the new R11) is developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

☐ Agree

☐ Disagree

Comments:

12. The SDT received suggestions from commenters to re-sequence the requirements contained in the standard to improve the logical flow of this document. The SDT submits for consideration a proposed alternative sequence. Do you agree with the proposed alternative sequencing? If not, please recommend a suggested sequence.

Proposed Alternative Sequence	Current Sequence	Description
R1	R11	PC to document method to determine sub 200kV lines
R2	R10	PC to prepare list of sub 200kV lines
R3	R1	Document TVMP
R4	R3	Conduct Vegetation Inspections
R5	R9	Implement Annual Work Plan
R6	R2	Implement Imminent Threat
R7	R4	Prevent Vegetation Encroachments
R8	R8	Prevent Fall-in Outages
R9	R7	Prevent Blow-in Outages
R10	R6	Prevent Grow-in Outages (non-IROL lines)
R11	R5	Prevent Grow-in Outages (IROL lines)

* If the standard is re-sequenced, it will be reflected in the next version.

☐ Agree

☐ Disagree

Comments:

13. The Implementation Plan proposes an effective date that gives entities at least a year to become fully compliant. Do you agree with this implementation plan? If not, please indicate what should be changed and indicate why.

☐ Agree

☐ Disagree

Comments:

14. Do you have further questions about the standard that the Technical Reference document (White Paper) does not clear up? If so, please elaborate and propose additions.

Comments:

15. As stated in the background information above, in response to industry comments, the applicability section is revised to replace Reliability Coordinator with Planning Coordinator. Do you agree with these changes? If not, please explain and propose an alternative.

☐ Agree

☐ Disagree

Comments:

16. As stated in the background information above, in response to industry comments, changes were made to the definitions. Do you agree with these changes? If not, please explain and propose an alternative.

☐ Agree

☐ Disagree

Comments:

17. When compared to Version 1, does this proposed Version 2 of the standard either maintain or improve overall electric reliability? Please provide a technical basis for your response?

☐ V2 Does maintain or improve overall reliability

☐ V2 Does not maintain or improve overall reliability

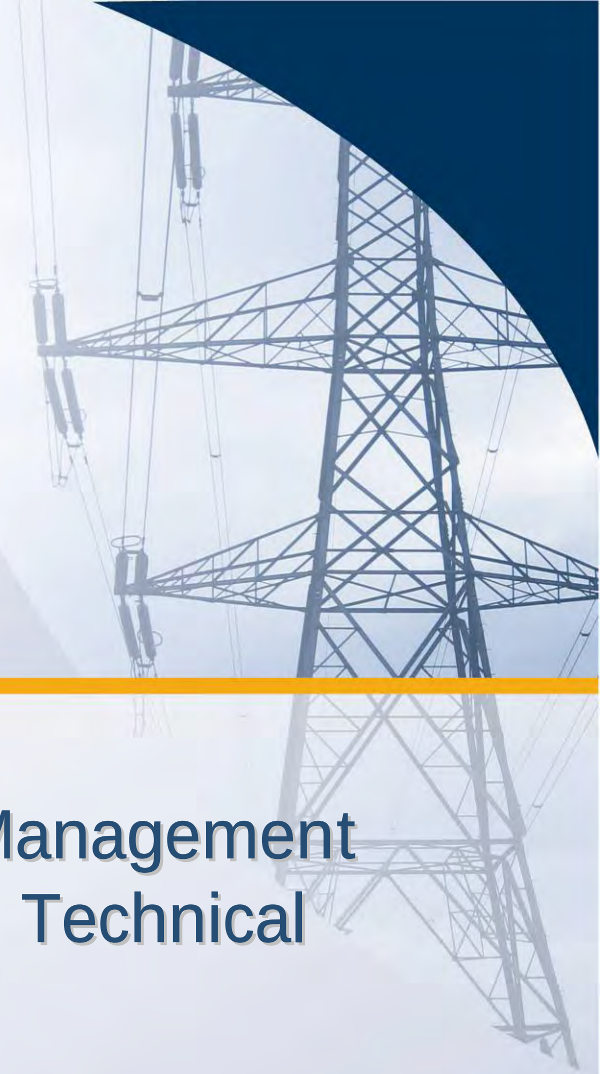
Comments:

18. Besides the comments you have already provided for the preceding questions, do you have further suggestions for improving this standard? If so, please elaborate.

Comments:

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION



Transmission Vegetation Management NERC Standard FAC-003-2 Technical Reference

Prepared by the North American Electric Reliability Corporation Vegetation Management Standard Drafting Team

to ensure the reliability of the bulk power system

September, 2009

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Table of Contents

Introduction

This document is intended to provide supplemental information and guidance for complying with the requirements of Reliability Standard FAC-003-2. It is a supporting document and provides explanatory background to the requirements of the Standard. The intentions of the Standard Drafting Team in developing many key areas of this Revision are also explained in this document.

The purpose of the Standard is to improve the reliability of the electric transmission system by preventing those vegetation related outages that could lead to Cascading.

Compliance with the Standard is mandatory and enforceable.

Disclaimer

This supporting document may explain or facilitate implementation of reliability standard FAC-003-2 — Transmission Vegetation Management but does not contain any additional mandatory requirements subject to compliance review.

Definition of Terms

Active Transmission Line Right of Way* — A strip of land that is occupied by active transmission facilities. This corridor does not include the inactive Right of Way or unused part of the Right of Way intended for other facilities.

Examples of inactive or unused portions of corridors include:

1) The portions of the right of way acquired to accommodate future facilities. Power plant exits are examples where large rights of way are obtained for maximum corridor utilization and may currently have fewer lines constructed.
2) The portion of the right of way where corridor edge zones (i.e., buffer zones) are provided for vegetation to exist.
3) The portions of the right of way where double-circuit structures are installed but only one circuit is currently strung with conductors.
4) Portions of the right of way with deactivated transmission lines that are unavailable for service.

Vegetation Inspection** — The systematic examination of vegetation conditions on an Active Transmission Line Right of Way. This inspection may be combined with a general line inspection. The inspection includes the documentation of any vegetation that may pose a threat to reliability prior to the next planned inspection or maintenance work, considering the current location of the conductor and other possible locations of the conductor due to sag and sway for rated conditions.

*To be added to the NERC glossary of terms with final approval of this standard revision
** This term is listed in the NERC glossary of terms, but has been modified for the purposes of this standard and is to be modified in the NERC glossary of terms with final approval of this standard revision

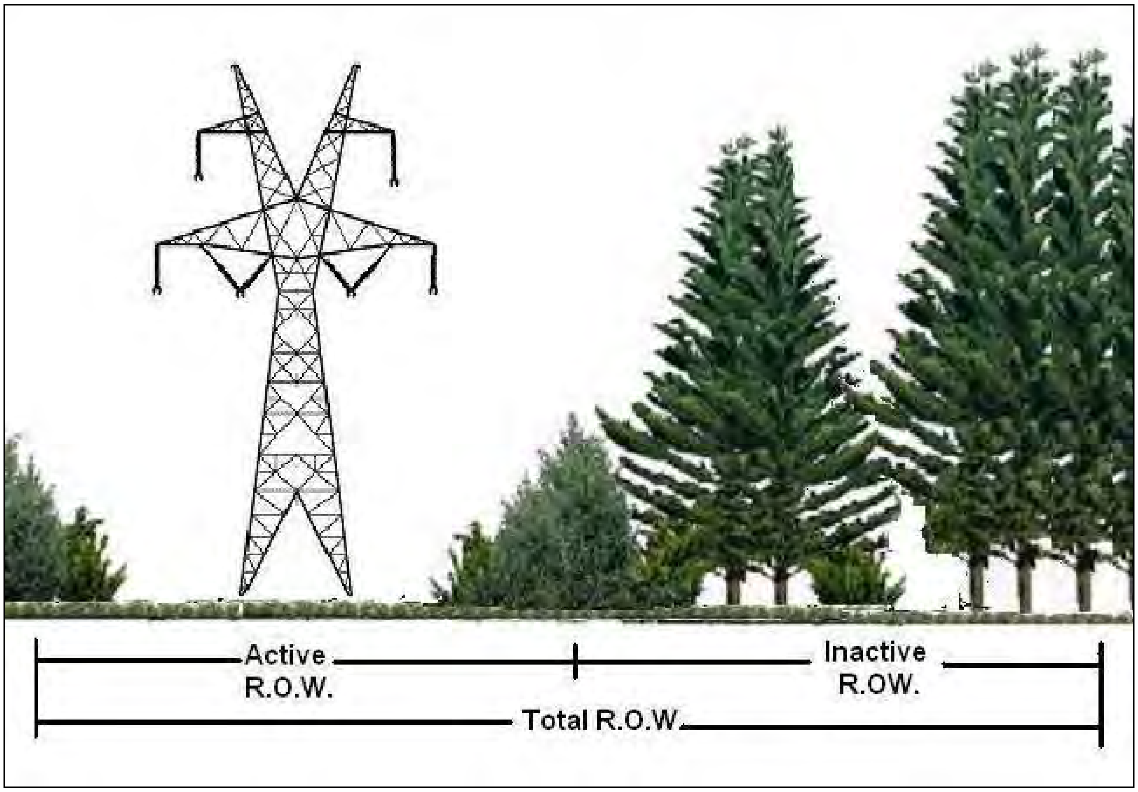

Figure 1

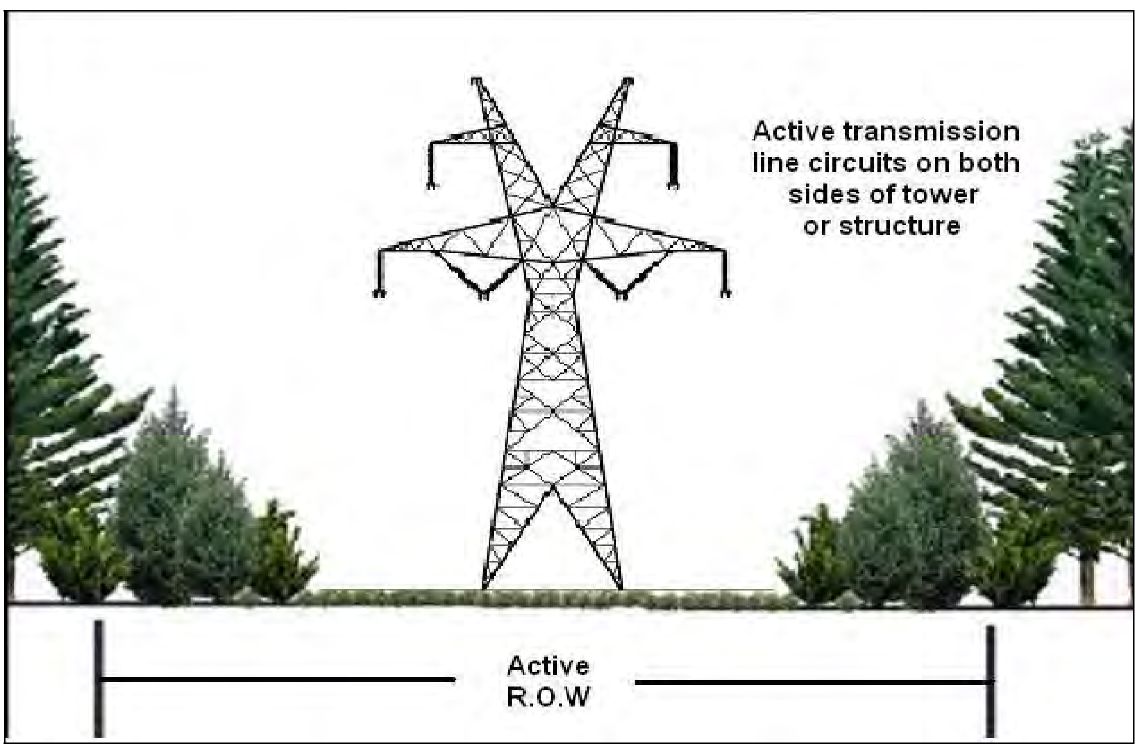

Figure 2

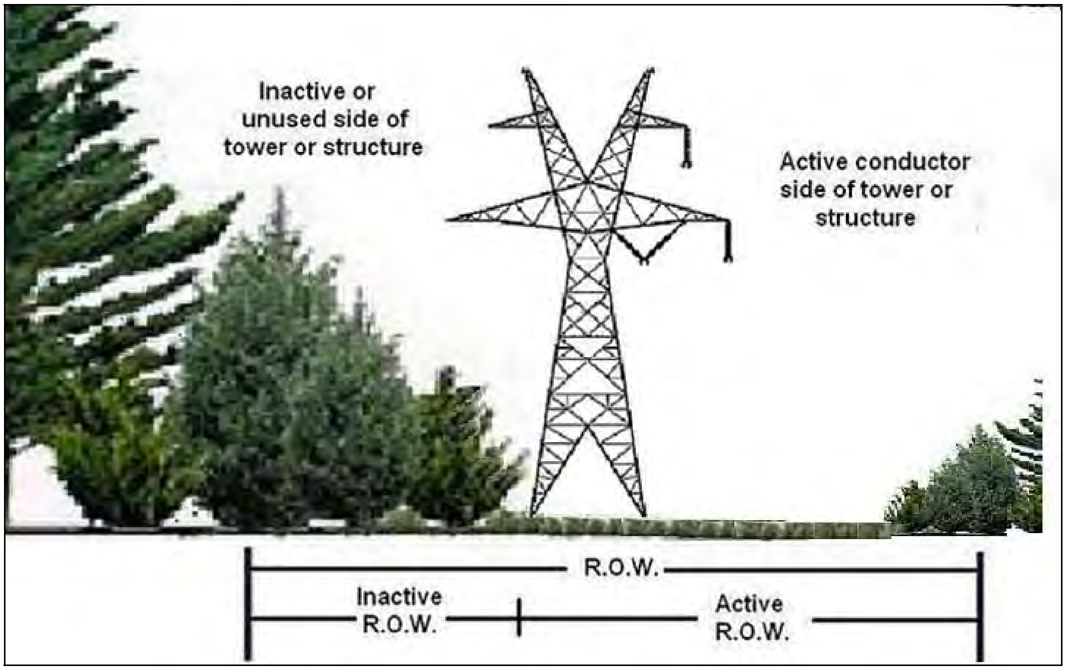
Inactive or
unused side of
tower or structure
Active conductor
side of tower or
structure
R.O.W.
Inactive
R.O.W.
Active
R.O.W.

Figure 3

Applicability of the Standard

4. *Applicability:*

Functional Entities:

- *Transmission Owner*
- *Planning Coordinator*

Facilities:

- *Transmission lines ("applicable lines") operated at 200kV or higher, and transmission lines operated below 200kV designated by the Planning Coordinator as being subject to this standard including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities.*
- *Transmission lines operated below 200kV designated by the Planning Coordinator as being subject to this standard become subject to this standard 12 months after the date the Planning Coordinator initially designates the transmission line as being subject to this standard.*
- *Existing transmission lines operated at 200kV or higher which are newly acquired by a Transmission Owner and were not previously subject to this standard, become subject to this standard 12 months after the acquisition date of the transmissions lines.*

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies"*

The reliability objective of this NERC Vegetation Management Standard ("Standard") is to prevent vegetation-related outages which could lead to Cascading by effective vegetation maintenance while recognizing that certain outages such as those due to vandalism, human errors and acts of nature are not preventable. Operating experience clearly indicates that trees that have grown out of specification could contribute to a cascading grid failure, especially under heavy electrical loading conditions.

Serious outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. To properly reduce and manage this risk, it is necessary to apply the Standard to applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee. For the purposes of the Standard and this technical paper, the term "public lands" includes municipal lands, village lands, city lands, and a host of other governmental entities.

The Standard addresses vegetation management along applicable overhead lines that serve to connect one electric station to another. However, it is not intended to be applied to lines sections inside the electric station fence or other boundary of an electric station or underground lines.

The Standard is intended to reduce the risk of Cascading involving vegetation. It is not intended to prevent customer outages from occurring due to tree contact with all transmission lines and voltages. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this Standard is not written to address such isolated situations which have little impact on the overall Bulk Electric System. In fact, the inclusion of such a transmission line (which does not lead to the undesirable conditions listed in Requirement R11) on the Planning Coordinator's list of sub-200kV lines may constitute a violation of Requirement R11.

Vegetation growth is constant and always present. Unmanaged vegetation poses an increased outage risk when numerous transmission lines are operating at or near their Rating. This poses a significant risk of multiple line failures and Cascading. On the other hand, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are statistically intermittent. The probability of occurrence of these events is not dependent on heavy loads. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures.

In preparing the original vegetation management standard in 2005, industry stakeholders set the threshold for applicability of the standard at 200kV. This was because an unexpected loss of lines operating at above 200kV has a higher probability of initiating a widespread blackout or cascading outages compared with lines operating at less than 200kV. Thus, the 200kV threshold was an arbitrary proxy for those circuits whose Sustained Outage might lead to a Cascade.

The NERC vegetation management standard FAC-003-1 also allowed for application of the standard to "critical" circuits (critical from the perspective of initiating widespread blackouts or cascading outages) operating below 200kV. While the percentage of these circuits is relatively low, it remains a fact that there are sub-200kV circuits whose loss could contribute to a widespread outage. Given the very limited exposure and unlikelihood of a major event related to these lower-voltage lines, it would be an imprudent use of resources to apply the Standard to all sub-200kV lines. The drafting team, after evaluating several alternatives, selected the Planning Coordinator as the best entity to determine applicable lines below 200kV that are subject to this standard in a time horizon that best matches requirements for vegetation management methods.

Transmission Vegetation Management Program

R1. *Each Transmission Owner shall have a documented transmission vegetation management program that describes how it conducts work on its Active Transmission Line Rights of Way to prevent Sustained Outages due to vegetation, considering all possible locations the conductor may occupy under the effects of sag and sway throughout its operating range under rated conditions. The transmission vegetation management program shall: [Violation Risk Factor: Lower][Time Horizon: Long-term planning]*

M1. *The Transmission Owner has a documented transmission vegetation management program (paper or electronic copy of dated, current, in force document with specified elements) that describes how it conducts work on its Active Transmission Line Rights of Way to prevent Sustained Outages due to vegetation, considering all possible locations the conductor may occupy under the effects of sag and sway throughout its operating range under rated conditions. (R1)*

The purpose of the Standard is to prevent vegetation-related outages that can result in Cascading. Under Requirement R1, each Transmission Owner is required to have a transmission vegetation management program (TVMP) designed to control vegetation on the Active Transmission Line Right of Way. The TVMP is an important component of the Standard because it is the formal document that Transmission Owners use to manage vegetation to achieve the purpose of the Standard. An adequate TVMP formally establishes the guidelines that are used by the Transmission Owner to plan and perform vegetation work that is necessary to prevent transmission outages and minimize risk to the transmission system.

Requirement R1 is concerned with the content of the TVMP and supporting documents, but does not address implementation of the elements of the TVMP. Other requirements address implementation of the TVMP. For example, sub-part 1.2 requires Transmission Owners to specify a vegetation inspection frequency. However, sub-part 1.2 does not address implementation of the inspection. This is addressed in Requirement R3.

The numbered "Parts" of Requirement 1 are elements of Requirement 1 and, while these parts identify performance that is mandatory, these parts do not constitute separate Requirements. For assessing compliance, each requirement has a single Violation Risk Factor and a single set of Violation Severity Levels so that compliance is assessed with the requirement, "in total."

Methods to Control Vegetation

R1

> ***1.1*** *The transmission vegetation management program shall specify the methods that the Transmission Owner may use to control vegetation.*[2]

[2] *ANSI A300, Tree Care Operations — Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.*

M1

> ***1.1*** *The Transmission Owner's transmission vegetation management program documentation specifies the methods that the Transmission Owner may use to control vegetation.*

Each Transmission Owner is required to specify the methods used to control vegetation on applicable lines in its transmission vegetation management program. The methods specified in the transmission vegetation management program under this requirement are the methods that will be applied to the development and implementation of the annual work plan (1.3 and R9).

The intent of Requirement R1, Part 1.1 is for the Transmission Owner to list and generally describe the vegetation management methods that are used on its Active Transmission Line Rights of Way. Transmission Owners are not required to deploy each of the methods listed in every situation. Nor are they required to provide a detailed description of each method, although these may exist in the Transmission Owner's specifications. Instead, the methods listed under this requirement are intended to provide a menu of vegetation management options that the Transmission Owner may deploy when developing and implementing its annual work plan based upon the many different circumstances that are typically encountered.

Pruning is an inefficient maintenance method. Removal is always superior to pruning in ensuring tree conflicts do not occur.

In general, the best management practice for the Transmission Owner is to exercise its maximum legal rights to achieve the objectives of the transmission vegetation management program. This minimizes the possibility of conflicts between energized conductors and vegetation. Since this is not always possible, the Transmission Owner's strategy should be to use its prescribed vegetation maintenance methods to work towards or achieve the maximum use of the Active Transmission Line Right of Way.

The following are several examples of how methods could be specified in the transmission vegetation management program under this requirement. These are offered as examples only and numerous other methods could be included in the transmission vegetation management program. More detailed descriptions would typically be included in the Transmission Owner's internal specifications and procedures. In summary, methods must be applied in a sound biological manner.

Mechanical Clearing — Remove all trees and brush in the Active Transmission Line Right of Way. Cut or mow all stumps to 3 inches or less above grade. De-limb and windrow on the edge of the right of way those larger trees that could be obstructive to other line maintenance activities.

Selective Mechanical Tree Removal — Selectively remove with chain saws or mechanized equipment all tall-growing species of trees, as listed in the specifications. Chemically treat the stumps of re-sprouting trees with the herbicide mixtures identified in the specification within one hour of making the cut. All low-growing species of shrubs and trees, as listed in the specification, will be preserved unless otherwise noted.

Low-Volume Foliar Selective Herbicide Treatment — Selectively treat with herbicide all tall-growing species of trees as listed in the specification which are less than ten feet in height, using the low-volume foliar herbicide mixture and application process listed in the specification. All low-growing species of shrubs and trees, as listed in the specification will be preserved unless otherwise noted.

Side Pruning — Prune trees adjacent to the Active Transmission Line Right of Way that have grown to an extent that they have encroached upon or will soon encroach upon the clearances listed in the specification. In cases where specified clearances can not be achieved due to Active Transmission Line Right of Way width restrictions, remove branches to prevent entry into the Active Transmission Line Right of Way.

ANSI A300 – Best Management Practices for Tree Care Operations

Transmission Owners have the option of adopting the procedures and practices contained in an industry-recognized ANSI Standard known as A300 for use as a central component of its vegetation management program. The following is a description of A300.

Introduction

Integrated Vegetation Management (IVM) is a best management practice conveyed in the American National Standard for Tree Care Operations, Part 7 (ANSI 2006) and the International Society of Arboriculture’s *Best Management Practices: Integrated Vegetation Management* (Miller 2007). IVM is consistent with the requirements in FAC-003-02, and it provides practitioners with what industry experts consider to be the most appropriate techniques to apply to electric right of way projects in order to exceed those requirements.

IVM is a system of managing plant communities whereby managers set objectives, identify compatible and incompatible vegetation, consider action thresholds, and evaluate, select and implement the most appropriate control method or methods to achieve set objectives. The choice of control method or methods should be based on their environmental impact and anticipated effectiveness, along with site characteristics, security, economics, current land use and other factors.

Planning and Implementation

Best management practices provide a systematic way of planning and implementing a vegetation management program. While designed primarily with transmission systems in mind, it is also

applicable to distribution projects. As presented in ANSI A300 part 7 and the ISA best management practices, IVM consists of 6 elements:

1) Set Objectives
2) Evaluate the Site
3) Define Action Thresholds
4) Evaluate and Select Control Methods
5) Implement IVM
6) Monitor Treatment and Quality Assurance

The setting of objectives, defining action thresholds, and evaluating and selecting control methods all require decisions. The planning and implementation process is cyclical and continuous, because vegetation is dynamic and managers must have the flexibility to adjust their plans. Adjustments may be made at each stage as new information becomes available and circumstances evolve.

Set Objectives

Objectives should be clearly defined and documented. Examples of objectives can include promoting safety, preventing outages caused by vegetation growing into electric facilities and minimizing them from trees growing outside the right of way, maintaining regulatory compliance, protecting structures and security, restoring electric service during emergencies, maintaining access and clear lines of sight, protecting the environment, and facilitating cost effectiveness.

Objectives should be based on site factors, such as workload and vegetation type, in addition to available human, equipment and financial resources. They will vary from utility to utility and project to project, depending on line voltage and criticality, as well as topographical, environmental, fiscal and political considerations. However, where it is appropriate, the overriding focus should be on environmentally-sound, cost effective control of species that potentially conflict with the electric facility, while promoting compatible, early successional, sustainable plant communities.

Work Load Evaluations

Work-load evaluations are inventories of vegetation that could have a bearing on management objectives. Work load assessments can capture a variety of vegetation characteristics, such as location, height, species, size and condition, hazard status, density and clearance from conductors. Assessments should be conducted considering voltage, conductor sag from ambient temperatures and loading, and the potential influence of wind on line sway.

Evaluations can be comprehensive or point sample, and can be done to obtain information on an entire program or an individual project. Comprehensive evaluations account for vegetation that could potentially affect management objectives, including hazard trees. Program-level comprehensive evaluations can be made of all target vegetation on a system, while project-level evaluations focus on vegetation relevant to a specific job. Comprehensive evaluations provide the advantage of supplying a complete set of data upon which to base management decisions. On the other hand, comprehensive surveys can be impractical for utilities with large numbers of trees, limited human and financial resources, or both.

Point sampling offers an alternative for utilities for which comprehensive inventories are impractical. Point sampling is cost effective, and has a proven track record for reasonable accuracy. A common method involves dividing a management area (a system or project) into equal-sized units and selecting a random sample sufficient to statistically represent the total work quantity. Random selection eliminates the chance of bias on the part of the investigator. Every plant or plant community of interest within each selected area is inventoried, with collected data used to forecast the total workload.

Evaluate and Select Control Methods

Control methods are the process through which managers achieve objectives. The most suitable control method best achieves management objectives at a particular site. Many cases call for a combination of methods. Managers have a variety of controls from which to choose, including manual, mechanical, herbicide and tree growth regulators, biological, and cultural options.

Manual Control Methods

Manual methods employ workers with hand-carried tools, including chainsaws, handsaws, pruning shears and other devices to control incompatible vegetation. The advantage of manual techniques is that they are selective and can be used where others may not be. On the other hand, manual techniques can be inefficient and expensive compared to other methods. If pruning is necessary, it should comply with ANSI A300 Part 1 (ANSI 2001) and ISA best management practices for utility pruning (Kempter 2004).

Mechanical Control Methods

Mechanical controls are done with machines. They are efficient and cost effective, particularly for clearing dense vegetation during initial establishment, or reclaiming neglected or overgrown rights of way. On the other hand, mechanical control methods can be non-selective and disturb sensitive sites.

Tree Growth Regulator and Herbicide Control Methods

Tree growth regulators and herbicides are essential for effective vegetation management. Tree growth regulators (TGRs) are designed to reduce growth rates by interfering with natural plant processes. TGRs can be helpful where removals are prohibited or impractical by reducing the growth rates of some fast-growing species.

Herbicides control plants by interfering with specific botanical biochemical pathways. Herbicide use can control individual plants that are prone to re-sprout or sucker after removal. When trees that re-sprout or sucker are removed without herbicide treatment, dense thickets develop, impeding access, swelling workloads, increasing costs, blocking lines-of-site, and deteriorating wildlife habitat. Treating suckering plants allows early successional, compatible species to dominate the right of way and out-compete incompatible species, ultimately reducing work.

Cultural Control Methods

Cultural methods modify habitat to discourage incompatible vegetation and establish and manage desirable, early successional plant communities. Cultural methods take advantage of seed banks of native, compatible species lying dormant on site. In the long run, cultural control is the most desirable method where it is applicable.

A cultural control known as cover-type conversion provides a competitive advantage to short-growing, early successional plants, allowing them to thrive and eventually out-compete unwanted tree species for sunlight, essential elements and water. The early successional plant community is relatively stable, tree-resistant and reduces the amount of work, including herbicide application, with each successive treatment.

Wire-Border Zone

The wire-border zone technique is a management philosophy that can be applied through cultural control. W.C. Bramble and W.R. Byrnes developed it in the mid-1980s out of research begun in 1952 on a transmission right of way in the Pennsylvania State Game Lands 33 Research and Demonstration project (Yahner and Hutnik (2004).

The wire zone is the section of a utility transmission right of way directly under the wires and extending outward about 10 feet on each side. The wire zone is managed to promote a low-growing plant community dominated by grasses, herbs and small shrubs (under 3 feet in height at maturity). The border zone is the remainder of the right of way. It is managed to establish small trees and tall shrubs (under 25 feet in height at maturity). When properly managed, diverse, tree-resistant plant communities develop in wire and border zones. The communities not only protect the electric facility and reduce long-term maintenance, but also enhance wildlife habitat, forest ecology and aesthetic values.

Although the wire-border zone is a best practice in many instances, it is not necessarily universally suitable. For example, standard wire-border zone prescriptions may be unnecessary where lines are high off the ground, such as across low valleys or canyons, so the technique can be modified without sacrificing reliability.

One way to accommodate variances in topography is to establish different regions based on wire height. For example, over canyon bottoms or other areas where conductors are 100 feet or more above the ground, only a few trees are likely to be tall enough to conflict with the lines. In those cases, trees that potentially interfere with the transmission lines can be removed selectively on a case-by-case basis.

In areas where the wire is lower, perhaps between 50-100 feet from the ground, a border zone community can be developed throughout the right of way. Note that in many cases, conductor attachment points are more than 50 feet off the ground, so a border zone community can be cultivated near structures. Where the line is less than 50 feet off the ground, managers could apply a full wire-border zone prescription.

An environmental advantage of this type of modification is stream protection. Streams often course through the valleys and canyons where lines are likely to be elevated. Leaving timber or border zone communities in canyon bottoms helps shelter this valuable habitat, enabling managers to achieve environmentally sensitive objectives.

Implement Integrated Vegetation Management (IVM)

All laws and regulations governing IVM practices and specifications written by qualified vegetation managers must be followed. IVM control methods should be implemented on regular work schedules, which are based on established objectives and completed assessments. Work should progress systematically, using control measures determined to be best for varying conditions at specific locations along a right of way. Some considerations used in developing schedules include the importance and type of line, vegetation clearances, work loads, growth rate of predominant vegetation, geography, accessibility, and in some cases, time lapsed since the last scheduled work.

Clearances Following Work

Clearances following work should be sufficient to meet management objectives, including preventing trees from entering the Minimum Vegetation Clearance Distance, electric safety risks, service-reliability threats and cost.

Monitor Treatment and Quality Assurance

An effective program includes documented processes to evaluate results. Evaluations can involve quality assurance while work is underway and after it is completed. Monitoring for quality assurance should begin early to correct any possible miscommunication or misunderstanding on the part of crewmembers. Early and consistent observation and evaluation also provides an opportunity to modify the plan, if need be, in time for a successful outcome.

Utility vegetation management programs should have systems and procedures in place for documenting and verifying that vegetation management work was completed to specifications. Post-control reviews can be comprehensive or based on a statistically representative sample. This final review points back to the first step and the planning process begins again.

Summary

IVM offers among others, a systematic way of planning and implementing a vegetation management program as presented in ANSI A300 Part 7. This methodology enables a program to comply with the NERC *Transmission Vegetation Management Program* standard (FAC-003-2). Managers should select control options to best promote management objectives.

Vegetation Inspection Frequency

R1

> **1.2** *The transmission vegetation management program shall specify a Vegetation Inspection frequency of at least once per calendar year that takes into account local*[4] *and environmental factors.*

M1

> **1.2** *The Transmission Owner's transmission vegetation management program documentation specifies a Vegetation Inspection frequency of at least once per calendar year that takes into account local and environmental factors.*

[4] Local factors include items such as treatment cycle, extent and type of treatment, and their relationship to the normal growth rate.

The Transmission Owner's Transmission Vegetation Management Program (TVMP) shall specify the frequency of vegetation inspections. The inspection frequency is required to be at least once per calendar year. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections. Such factors may include anticipated growth rates of the local vegetation, length of the growing season for the geographical area, limited Active Transmission Line Right of Way widths, rainfall amounts, etc.

Annual Plans

R1

> ***1.3.*** *The transmission vegetation management program shall require an annual work plan. An annual work plan shall:*
>
> ***1.3.1*** *Identify the applicable lines to be maintained*
>
> ***1.3.2*** *Identify the work to be performed and methods to be used*
>
> ***1.3.3*** *Be flexible to adjust to changing conditions and to findings from Vegetation Inspections. Adjustments to the plan within the year are permissible.*
>
> ***1.3.4*** *Take into consideration permitting and scheduling requirements from landowners or regulatory authorities.*

M1

> ***1.3*** *The Transmission Owner's transmission vegetation management program contains an annual work plan which:*
>
> ***1.3.1*** *Identifies the applicable lines to be maintained*
>
> ***1.3.2*** *Identifies the work to be performed and the methods used*
>
> ***1.3.3*** *Shows flexibility to adjust to changing conditions and to findings from Vegetation Inspections*
>
> ***1.3.4*** *Considers permitting and scheduling requirements from landowners or regulatory authorities*

The work plan is not intended to be a "span-by-span" detailed description of all work to be performed. It is intended to require the Transmission Owner to annually plan and schedule vegetation work to prevent encroachment into the Minimum Vegetation Clearance Distance. Work plans can vary in their level of detail.

The flexibility to adjust the annual work plan in response to changing conditions must not be invoked in a manner that adversely impacts reliability. The intent of the standard drafting team was to allow adjustments for changing conditions of the vegetation on the Active Transmission Line ROW, emergencies, and other significant changing conditions, and not for budget constraints. Annual work plan adjustments must always ensure the reliability of the electric transmission system.

This Standard requires that the annual work plan be flexible to allow the Transmission Owner to change priorities during the year as conditions or situations dictate. For example, weather conditions (drought) could make herbicide application ineffective during the plan year. Another situational variance could be a major storm that redirects local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the Transmission Owner's system to work on another system. Examples of adjustments may include deferrals or additions to the annual work plan.

The drafting team cites the following conditions that may result in adjustments to the annual work plan: abnormal weather such as drought, major storms, excessive rainfall, other environmental conditions such as infestation, disease, fire, etc. These conditions may be found as part of a special or scheduled Vegetation Inspection. Examples of annual work plan adjustments that are permitted may include revising the work plan priorities, rescheduling work to another time or selecting alternate vegetation control methods. Changes in land usage made by a property owner, such as timber clearing, may be another condition that warrants an adjustment.

When developing the annual work plan the Transmission Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Transmission Owners may also need to consider those special landowner requirements as documented in easement instruments.

Vegetation Imminent Threat Procedure

R1.

> ***1.4*** *The transmission vegetation management program shall require a process or procedure for response to an imminent threat of a vegetation-related Sustained Outage. The process or procedure shall specify actions which shall include communication of the threat to the responsible control center.*

M1.

> ***1.4*** *The Transmission Owner's transmission vegetation management program documentation specifies an imminent threat process or procedure for responding to imminent threats of a vegetation-related Sustained Outage including communication of the threat to the responsible control center.*

The term "imminent threat" refers to a vegetation condition which is likely to cause a Sustained Outage at any moment. An imminent threat requires immediate action by the Transmission Owner to alert the responsible control center (usually the Transmission Operator) that there is an increased probability of the occurrence of a Sustained Outage.

Two key elements of an acceptable imminent threat process or procedure are outlined below:

- Specify the vegetation-related conditions that warrant a response:

  Examples of these vegetation-related conditions include vegetation that is near or encroaching into the MVCD (growth issue) or vegetation that presents an imminent danger of falling into the transmission conductor (fall-in issue).

- Notify the responsible control center:

  So that the responsible control center holds situational awareness of known risks to the power system, the Transmission Owner has the responsibility to ensure the proper communication between field personnel and the responsible control center. This will allow the responsible control center to take the appropriate action until the threat is relieved. Appropriate actions may include, but are not limited to, a temporary reduction in the line loading, or switching the line out of service.

  The protocol for contacting the responsible control center should be defined. For example, some Transmission Owners' processes may require a call directly to the responsible control center, while other Transmission Owners may require a call to a supervisor or field forester who will in turn notify the responsible control center .

The urgency of vegetation-related imminent threats may be contrasted with the longer time frames of interim corrective action plans which are developed from a corrective action process as defined in Requirement R1, Part 1.5.

The imminent threat process or procedure should be implemented in terms of minutes or hours as opposed to a longer time frame for interim corrective action plans.

All serious growth or fall-in vegetation-related conditions are not necessarily considered imminent threats under the Standard. For example, some Transmission Owners may have a danger tree identification program that identifies for removal trees with the potential to fall near the line. These trees are not necessarily considered imminent threats under the Standard unless they pose an immediate fall-in threat.

Also, there can be situations involving vegetation that are not considered vegetation-related imminent threats under the Standard. For example, a logging operation on or near the Active Transmission Line Right of Way can pose an immediate threat of a sustained outage and result in the initiation of an imminent threat process in the same manner as the presence of a nearby crane or the notification of a hot-spot on a conductor connector. Although the logging threat in this example tangentially involves vegetation, it is not considered a vegetation-related imminent threat under the Standard.

Interim Corrective Action Process

R1.

1.5. *The transmission vegetation management program shall specify an interim corrective action process for use when the Transmission Owner is temporarily constrained from performing vegetation maintenance as planned.*

M1

1.5 *The Transmission Owner's transmission vegetation management program documentation specifies the interim corrective action process for use when the Transmission Owner is temporarily constrained from performing vegetation maintenance as planned.*

The intent of this requirement is to deal with situations that temporarily prevent the Transmission Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. This is not intended to address situations where an alternate work method can be substituted for the planned method. For example, a land owner may prevent the planned use of chemicals but allow the use of mechanical clearing. In this case the Transmission Owner can still perform work sufficient to eliminate the risk to the transmission line and does not need an interim corrective action plan. However, in situations where transmission line reliability is at risk due to a constraint and an alternate work method will not suffice, the Transmission Owner is required to develop a specific interim corrective action plan to mitigate the potential risk to the transmission line during the interim period.

The interim corrective action process should be flexible to provide a framework that can be applied over a wide range of situations to ensure line reliability.

Elements of the interim corrective action process include:

- Identifying locations where the Transmission Owner is constrained from performing planned vegetation maintenance work.
- Developing the specific plan to mitigate the risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific plan for each location.

Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the Transmission Owner's rights, or other circumstances.

In developing a specific plan to mitigate the risk to the transmission line, the Transmission Owner could consider location-specific measures such as modifying inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action plan could include limiting the loading on the transmission line.

The Transmission Owner should document and track each specific corrective action work plan by location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Maintenance Strategies

R1.

> ***1.6*** *The transmission vegetation management program shall specify the maintenance strategies used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that Table 1 clearances in FAC-003-2-Attachment 1 are never violated. The maintenance strategies shall consider the sag and sway of the conductor throughout its operating range under rated conditions.*

M1.

> ***1.6*** *The Transmission Owner's transmission vegetation management program documentation specifies the maintenance strategies used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that Table 1 clearances in FAC-003-2-Attachment 1 are never violated. The maintenance strategies consider the sag and sway of the conductor throughout its operating range under rated conditions.*

For a Transmission Owner to develop a specific maintenance strategy, it is important to understand the dynamics of a line conductor's movement. First, the complexities inherent in observing and predicting conductor movement, particularly for field personnel, will be addressed. Then, some examples of maintenance strategies that take into account these complexities will be described.

The phrase in Requirement R1 Part 1.6 that reads ". . . ensure that Table 1 clearances in FAC-003-2-Attachment 1 are never violated." is intended to require the TO to design its maintenance strategies considering all possible locations of the conductor for rated design conditions, and not to suggest that a compliance violation exists merely by a possible future proximity of the conductor to vegetation. Requirement R4 indicates that a real-time MVCD encroachment will result in a compliance violation.

Understanding Conductor Position and Movement

The conductor's position in space at any point in time changes as a reaction to a number of different loading variables. Vertical and horizontal conductor movement results from variations in thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading

When calculating the range of conductor positions, the Transmission Owner should use the same design criteria and assumptions that the Transmission Owner uses when establishing Ratings. Typically, the greatest conductor movement is at mid-span. As the conductor moves through various positions, a spark-over zone surrounding the conductor moves with it. The radius of the spark-over zone may be found by referring to Table 1 ("Minimum Vegetation Clearance Distances") in the standard. For illustrations of this zone and conductor movements, Figures 4 through 6 on the following pages demonstrate these concepts. At the time of making a field observation, however, it is very difficult to precisely know where the conductor is in relation to its wide range of all possible positions. Therefore, Transmission Owners must adopt maintenance strategies that account for this dynamic situation.

Selecting a Maintenance Strategy

To maintain adequate separation between vegetation and transmission line conductors, the Transmission Owner must craft a maintenance strategy that keeps vegetation well away from the spark-over zone mentioned above. In fact, it is generally necessary to incorporate a variety of maintenance strategies. For example, one Transmission Owner may utilize a combination of routine cycles, traditional Integrated Vegetation Management (IVM) techniques and long-term planning. Another Transmission Owner may place a higher reliance on frequent inspections and quick remediation as opposed to a cyclical approach. This variation of strategies is further warranted when factors, such as terrain, legal and other constraints, vegetation types, and climates, are considered in developing a Transmission Owner's specific strategy to satisfying this requirement.

The following is a sample description of one combination of strategies which may be utilized by a Transmission Owner.

A Transmission Owner's basic maintenance strategy could be to remove all incompatible vegetation from the right of way if it has the right to do so and has no constraints. In mountainous terrain, however, this strategy could change to one where the Transmission Owner manages vegetation based on vegetation-to-conductor clearances, since it might not be necessary to remove vegetation in a valley that is far below.

If faced with constraints and assuming a line design with sufficient ground clearance, the Transmission Owner 's strategy could then be to allow vegetation such as fruit trees, but perhaps only up to a given height at maturity (perhaps 10 feet from the ground). If constraints cannot be overcome and if design clearances are sufficient, an exception to the Transmission Owner's 10-foot guideline might be made. Finally, if the Transmission Owner has chosen to utilize vegetation-to-conductor clearance distance methods, the Transmission Owner could have an inspection regimen in place to regularly ensure that any impending clearance problems are identified early for rectification.

Additional information regarding proper maintenance strategies for achieving and ensuring Table I clearances can be found in the "Methods to Control Vegetation" and "Vegetation Inspection Frequency" sections of this document.

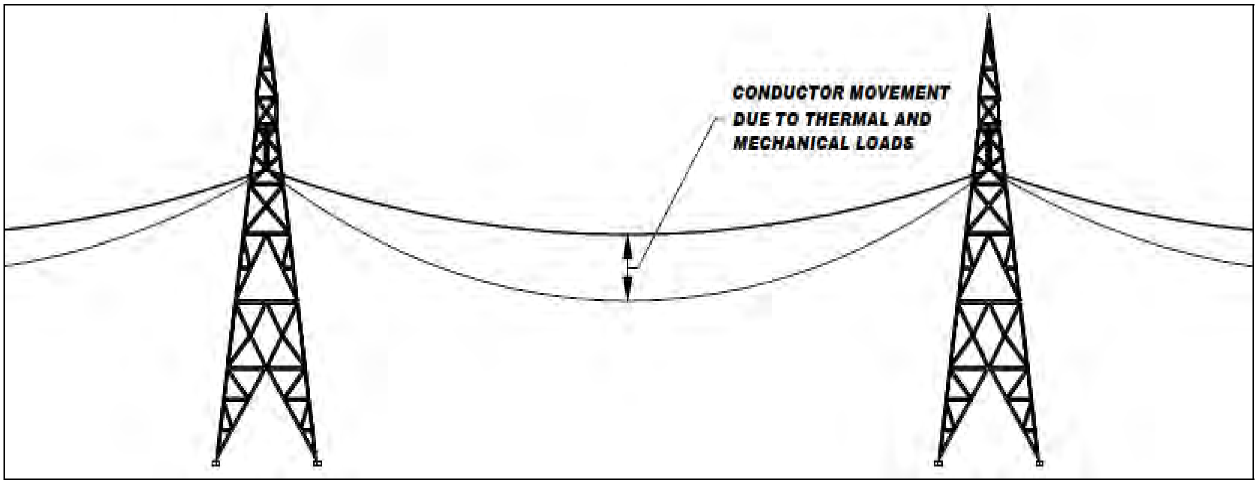

Figure 4

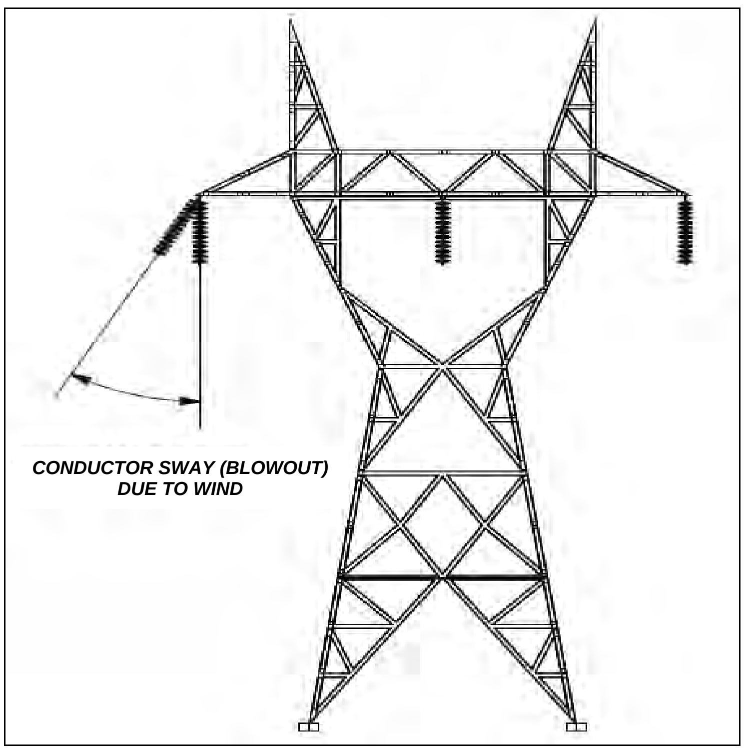

Figure 5

Cross-Section View of a Single Conductor
at a Given Point along the Span
Showing Six Possible Conductor Positions Due to Movement
Resulting from Thermal and Mechanical Loading
For Consideration in Developing a Maintenance Strategy

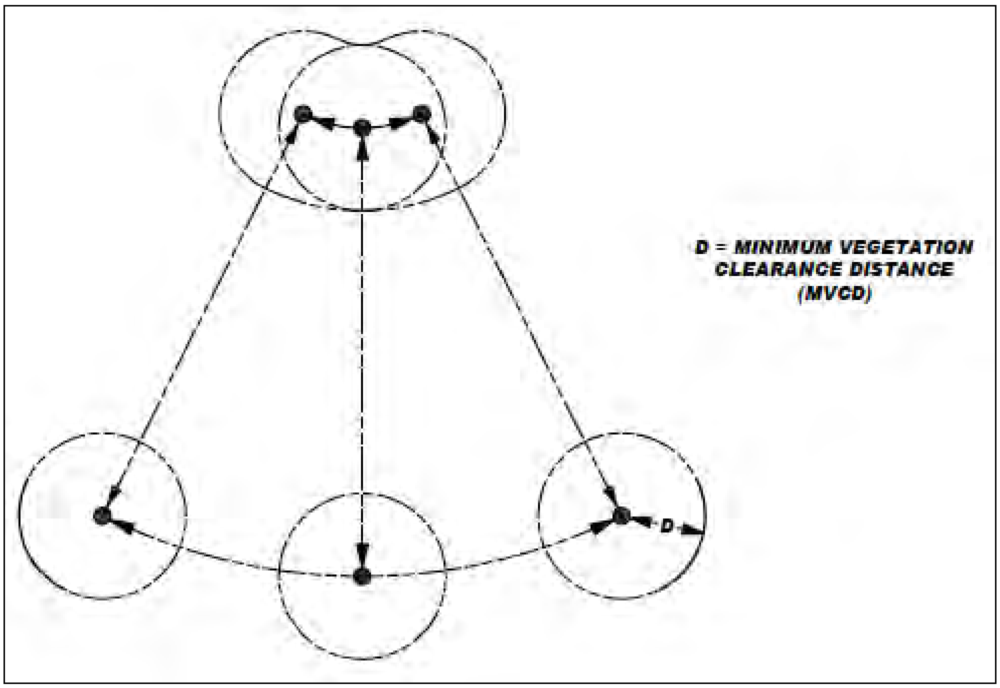

Figure 6

Implement Imminent Threat Procedure

R2. *Each Transmission Owner shall implement its imminent threat process or procedure when the Transmission Owner has actual knowledge of such a threat, obtained through normal operating practices. [Violation Risk Factor- Medium][Time Horizon – Real Time]*

M2. *The Transmission Owner has evidence of the implementation of its vegetation imminent threat process or procedure showing what was done with dates and activities accomplished. (R2)*

Each Transmission Owner must implement its imminent threat process or procedure when the Transmission Owner becomes aware of and confirms the existence of such a vegetation-related threat. The Transmission Owner could learn of the threat through a variety of normal operating practices, including routine line inspections, reports from landowners, observations made by public safety agencies or other utilities, etc. If a situation requires the Transmission Owner to implement its imminent threat process or procedure, it must retain some evidence of the threat and its response as outlined by Measure M2.

Conduct Vegetation Inspections

R3. *Each Transmission Owner shall conduct Vegetation Inspections of all applicable lines (as measured in line miles) in accordance with the frequency specified in its transmission vegetation management program, unless constrained by natural disasters[4]. When constrained by a natural disaster, the Transmission Owner shall conduct the Vegetation Inspection(s) within six months or a period agreed to by its Regional Entity, whichever is greater. [Violation Risk Factor: Medium][Time Horizon: Operations Planning]*

[4] Examples include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods.

M3. *The Transmission Owner has evidence that it conducted Vegetation Inspections in accordance with Requirement R3.*

This requirement is the implementation requirement for the Vegetation Inspections identified in Requirement R1, Part 1.2. The Standard allows Vegetation Inspections to be performed in conjunction with general line inspections. The inspections will be measured in line miles based on the defined inspection frequency.

The measure of “line miles” was selected so that if a Transmission Owner were to fail to completely inspect its system according to its stated frequency, an appropriate Violation Severity Level would be determined based upon the percentage of the system that was actually inspected.

As an example, where a Transmission Owner operates 1,000 miles of 230kV transmission lines with a stated Vegetation Inspection frequency (Requirement R1, Part 1.2) of twice per year; this Transmission Owner will be responsible for inspecting all 1,000 miles of 230kV transmission lines two times during the calendar year. This would yield a “total line miles inspection plan” of 2,000 miles for that calendar year.

Continuing with this example, if the Transmission Owner completed inspections of more than 1900 miles or 95% of its 2,000-mile but not 100% of the full 2000 miles, then, a VSL of “Moderate” would be used in determining a sanction.

In the event that extensive resources are devoted to a lengthy service restoration following a natural disaster on its own system or by assisting another utility, the Transmission Owner is permitted to reasonably postpone its line inspections until the resource constraint is relieved.

Encroachments within the "Minimum Vegetation Clearance Distances"

R4. *Each Transmission Owner shall prevent encroachment of vegetation into the Minimum Vegetation Clearance Distances (MVCD) listed in FAC-003-2-Attachment 1 for its applicable lines as observed in real-time operating between no-load and their Rating, with the following exceptions: [Violation Risk Factor VRF= Medium][Time Horizon – Real Time]*

- *Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from natural disasters.*[4]
- *Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from human or animal activity.*[5]
- *Brief encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from falling vegetation.*

[4] Examples include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods.

[5] Examples include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation.

M4. *The Transmission Owner has evidence from inspections that indicate there was no vegetation encroachment into the Minimum Vegetation Clearance Distances listed in FAC-003-2-Attachment 1 for its applicable lines as observed in real-time operating between no-load and their Rating, considering exceptions. (R4)*

This requirement indicates that if a Transmission Owner observes vegetation at a distance less than that prescribed in Table 1 of FAC-003-2-Attachment 1, it is in violation of this standard since sparkover is likely to occur. Requirement R4 refers to observation in "real time". This is an actual field observation or measurement of the conductor-to-vegetation distance and is not to be a calculated separation between the conductor and the vegetation

When possible encroachments of the MVCD are discovered through inspections or other means, the Transmission Owner must take appropriate action, which might include initiating vegetation management activities or implementation of its imminent threat process. If there is a confirmed clearance violation, the Transmission Owner must report to the Regional Entity as appropriate.

Certain exceptions are recognized in the Standard, including provisions for natural disasters and human or animal activity. Also, brief encroachments by falling vegetation are not considered to be a violation.

This requirement applies to transmission lines that are operating within their Rating. If a line is intentionally or inadvertently operated beyond its rating (potentially in violation of other standards), the occurrence of a clearance encroachment would not be a violation of this Standard. An encroachment of the MVCD that results from operation of a transmission line beyond its recognized Rating (for example emergency actions taken by an operator to protect an Interconnection) is beyond the scope of this standard.

Sustained Outages — Vegetation Growing Into Conductor

R5. *Each Transmission Owner shall prevent Sustained Outages*[6] *of applicable lines that are identified as an element of an Interconnection Reliability Operating Limit (IROL) (or Major WECC Transfer Path) due to vegetation growing into a conductor operating between no-load and its Rating, with the following exceptions: [Violation Risk Factor – High][Time Horizon – Real Time]*

- Sustained Outages of applicable lines that result from natural disasters.[4]
- Sustained Outages of applicable lines that result from human or animal activity.[5]

M5. *The Transmission Owner's self-certification reports are adequate evidence of no Sustained Outage of any applicable line that is identified as an element of an IROL (or Major WECC Transfer Path) due to vegetation growing into a conductor operating between no-load and its Rating. (R5)*

R6. *Each Transmission Owner shall prevent Sustained Outages*[6] *of applicable lines that are not an element of an IROL (or Major WECC Transfer Path) due to vegetation growing into a conductor operating between no-load and its Rating, with the following exceptions [Violation Risk Factor – High][Time Horizon – Real Time]*

- Sustained Outages of applicable lines that result from natural disasters.[4]
- Sustained Outages of applicable lines that result from human or animal activity.[5]

M6. *The Transmission Owner's self-certification reports are adequate evidence of no Sustained Outage of any applicable line that is not identified as an element of an IROL (or Major WECC Transfer Path) due to vegetation growing into a conductor operating between no-load and its Rating. (R6)*

[4] Examples include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods.

[5] Examples include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation.

[6] Multiple Sustained Outages on an individual line, if caused by the same vegetation, shall be considered as one outage regardless of the actual number of outages within a 24-hour period.

Vegetation grow-in events have contributed to several major blackouts and present a potential risk to the electric transmission system. Requirements R5 and R6 have been established to convey the seriousness of an outage caused by a vegetation grow-in and to distinguish between lines of differing impact to the system. Outages on certain lines are more likely to cause Cascading than on others. Accordingly, R5 applies to lines associated with IROLs (or major WECC transfer paths) and has been assigned a High Violation Risk Factor due to the higher probability of leading to a Cascading event. R6 applies to lines which are not associated with an

IROL (or major WECC transfer path) and has been assigned a Medium Violation Risk Factor, since outages on such lines are less likely to cause a Cascading event.

Planning Coordinators in planning time, and Reliability Coordinators in real time, determine operating limits for circuits or groups of circuits that may impact interconnected system reliability. The implication is that if these limits are exceeded; cascading, uncontrolled separation, instability, or voltage collapse might occur. Therefore these circuits or groups of circuits need to be protected from the risk of vegetation related outages. Planning Coordinators are required to identify circuits or groups of circuits that make up an IROL in NERC Standard FAC-010, Reliability Coordinators in FAC-011.

In the Western Interconnection there are some circuits or groups of circuits that do not meet the definition of an IROL, but nonetheless are very important to that Interconnection. Theses circuits or groups of circuits are classified as Major WECC Transfer Path(s) in the Western Interconnection. These are found in NERC Standard TOP-007-WECC-1.

It is important to note that for a Sustained Outage to be classified as a vegetation-related event, the conductor must be operating between no load and its Rating when the event occurs. Events that occur when the conductor is operating beyond its Rating would not be classified as vegetation-related Sustained Outages under the Standard.

Vegetation-related Sustained Outages that occur due to natural disasters are beyond the control of the Transmission Owner. These events are not classified as vegetation-related Sustained Outages and are therefore exempt from the Standard. Transmission lines are not designed to withstand the impacts of natural disasters such as tornadoes, hurricanes, severe ice loads, landslides, etc.

Sustained Outages due to human or animal activity are also beyond the control of the Transmission Owner are not classified as vegetation-related Sustained Outages and are therefore exempt from the Standard. Examples of these events may include new plantings of tall vegetation under the transmission line planted since the last Vegetation Inspection, tree contacts with line initiated by vehicles, logging activities, etc.)

Multiple Sustained Outages on an individual line can be caused by the same vegetation. Such events within a 24 hour period are considered to be a single vegetation-related Sustained Outage under the Standard. For example, a Sustained Outage caused by a tree could be mistakenly attributed to something else (e.g. contaminated insulator string, lightning, etc). After the apparent cause of the outage is addressed the line could be re-energized without the root cause being identified and removed. The transmission line could remain energized for a period of time while the thermal loading on the transmission line builds back to the point where the conductor contacts the same tree that caused the earlier Sustained Outage. These multiple outages resulting from the same tree would be considered as a single outage as long as all Sustained Outages occurred within a 24 hour period.

The Transmission Owner must self-certify each year that all vegetation-related Sustained Outages are documented and reported. If no vegetation-related Sustained Outages have occurred, a null report is sufficient documentation of compliance with these requirements.

Sustained Outages — Vegetation and Conductor Blowing Together

R7. *Each Transmission Owner shall prevent Sustained Outages[6] of applicable lines due to the blowing together of vegetation and a conductor within an Active Transmission Line Right of Way (operating within design blow-out conditions) with the following exception: [Violation Risk Factor - Medium][Time Horizon - Real Time]*

- Sustained Outages of applicable lines that result from natural disasters[4] or wind-blown debris.

[4] Examples include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods.

[6] Multiple Sustained Outages on an individual line, if caused by the same vegetation, shall be considered as one outage regardless of the actual number of outages within a 24-hour period.

M7. *The Transmission Owner's self-certification reports are adequate evidence of no Sustained Outage of any applicable line due to the blowing together of vegetation and a conductor within the Active Transmission Line Right of Way. (R7)*

This requirement is intended to prevent vegetation-related risk of a Cascading event on the electric transmission system by requiring the Transmission Owner to manage vegetation such that a vegetation-related Sustained Outage due to blowing together of vegetation and conductor does not occur.

Again, for a Sustained Outage to be classified as a vegetation-related event, the conductor must be operating between no load and its Rating when the event occurs. Events that occur when the conductor is operating beyond its Rating are not classified as vegetation-related Sustained Outages under the Standard. Also, this requirement clarifies that the conductor and the vegetation must be within the Active Transmission Line Right of Way.

Vegetation-related Sustained Outages that occur due to natural disasters are beyond the control of the Transmission Owner. These events are not classified as vegetation-related Sustained Outages and are therefore exempt from the Standard. Transmission lines are not designed to withstand the impacts of natural disasters such as tornadoes, hurricanes, severe ice loads, landslides, etc. Additionally, Sustained Outages due to wind-blown debris, such as large limbs and branches, separated tree tops, etc., are exempt from the Standard.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. Such events within a 24 hour period are considered to be a single vegetation-related Sustained Outage under the Standard. For example, a Sustained Outage caused by a tree could be mistakenly attributed to something else (e.g. contaminated insulator string, lightning, etc). After the apparent cause of the outage is addressed the line could be re-energized without the root cause being identified and removed. The transmission line could remain energized for a period of time while the thermal loading on the transmission line builds back to the point where the conductor contacts the same tree that caused the earlier Sustained Outage. These multiple outages resulting from the same tree would be considered as a single outage as long as all Sustained Outages occurred within a 24 hour period**.**

The Transmission Owner must self-certify each year that all vegetation-related Sustained Outages are documented and reported. If no vegetation-related Sustained Outages have occurred, a null report is sufficient documentation of compliance.

Sustained Outages — Vegetation Falling Into Conductor

R8. *Each Transmission Owner shall prevent Sustained Outages[6] of applicable lines due to vegetation falling into a conductor from within an Active Transmission Line Right of Way with the following exceptions: [Violation Risk Factor - Medium] [Time Horizon - Real Time]*

- *Sustained Outages of applicable lines that result from natural disasters[4] or wind-blown debris.*
- *Sustained Outages of applicable lines that result from human or animal activity.[5]*

[4] Examples include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods.

[5]Examples include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation.

[6] Multiple Sustained Outages on an individual line, if caused by the same vegetation, shall be considered as one outage regardless of the actual number of outages within a 24-hour period.

M8. *The Transmission Owner's self-certification reports are adequate evidence of no Sustained Outage of any applicable line due to vegetation falling into a conductor from within the Active Transmission Line Right of Way. (R8)*

This requirement is intended to prevent vegetation-related risk of a Cascading event on the electric transmission system by requiring the Transmission Owner to manage vegetation to prevent a vegetation-related Sustained Outage due to vegetation falling into a conductor from within the Active Transmission Line Right of Way.

Note that for a Sustained Outage to be classified as a vegetation-related event, the conductor must be operating between no load and its Rating when the event occurs. Events that occur when the conductor is operating beyond its Rating are not classified as vegetation-related Sustained Outages under the Standard. Also, this requirement clarifies that the conductor and the vegetation must be within the Active Transmission Line Right of Way.

Vegetation-related Sustained Outages that occur due to natural disasters are beyond the control of the Transmission Owner. These events are not classified as vegetation-related Sustained Outages and are therefore exempt from the Standard. Transmission lines are not designed to withstand the impacts of natural disasters such as tornadoes, hurricanes, severe ice loads, landslides, etc. Additionally, Sustained Outages due to wind-blown debris, such as large limbs and branches, separated tree tops, etc., are exempt from the Standard.

Sustained Outages due to human or animal activity are beyond the control of the Transmission Owner. These events would not be classified as vegetation-related Sustained Outages and are exempt from the Standard. Examples of these events may include new plantings of tall vegetation under the transmission line planted since the last Vegetation Inspection, tree contacts with line initiated by vehicles, logging activities, etc.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. Such events are considered to be a single vegetation-related Sustained Outage under the Standard.

The Transmission Owner must self-certify each year that all vegetation-related Sustained Outages are documented and reported. If no vegetation-related Sustained Outages have occurred, a null report is sufficient documentation of compliance.

Implement Annual Work Plan

R9. *Each Transmission Owner shall implement its annual work plan for vegetation management to accomplish the purpose of this standard. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M9. *The Transmission Owner has evidence that it is implementing, or has implemented, its annual work plan. An example of evidence is a paper or electronic copy of work plan and work records. (R9)*

This requirement sets the expectation that the work identified in the annual work plan (Requirement R1, Part 11.3) will be completed as planned.

Documentation or other evidence of the work performed typically consists of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, work inspection reports and walk-through reports.

Documentation is required when the annual work plan is adjusted or not completely implemented as originally planned. The reasons for the deferrals or changes and the expected completion date of postponed work should be documented.

The Transmission Owner's vegetation maintenance work necessary to implement the annual work plan is most effective when performed to the maximum extent allowed by any easement, fee simple and other legal rights. The Transmission Owner, therefore, should endeavor as a best practice to maintain its Active Transmission Line Right of Way to the full extent of its legal rights at all times and in all cases.

Designating Sub-200kV Lines

R10. *Each Planning Coordinator shall prepare and review annually, a list of lines that are operated below 200kV, if any, which are subject to this standard. Each Planning Coordinator shall consult with its Transmission Owner and neighboring Planning Coordinator to obtain to develop the list [Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning]*

M10. *The Planning Coordinator has evidence that it consulted with its Transmission Owner(s) and neighboring Planning Coordinator(s), prepared and reviewed annually a list of designated sub-200kV transmission lines, if any, which are subject to this standard. (R10)*

Requirement R10 assigns to the Planning Coordinator the task of designating sub-200kV lines that are subject to this standard. The Planning Coordinator is appropriate because it operates within a time horizon that allows a vegetation manager to develop and implement the necessary vegetation management plan.

The Standard places the responsibility on the Planning Coordinator for the identification of specific sub-200kV circuits to which the Standard is to be applied. Identification of such sub-200kV circuits is to be done in consultation with the Planning Coordinator's Transmission Owners and neighboring Planning Coordinators. This is intended to ensure that the individual Transmission Owners at the two ends of interconnections will receive identical signals regarding applicability of the Standard to the line in question.

Planning Coordinators, using their methodologies described in R11, will need to conduct the necessary studies and identify candidate sub-200kV transmission lines for potential applicability under the Standard. The Planning Coordinators will next need to consult with its Transmission Owners and neighboring Planning Coordinators to resolve any differences in the selection of sub-200kV transmission lines of common interest. Finally, the Planning Coordinator will need to finalize, adopt, and issue the list of designated sub-200kV lines.

For audit purposes, Planning Coordinators can offer documentation that they have consulted with their Transmission Owners and neighboring Planning Coordinators and that they have reviewed annually the list of designated sub-200kV transmission lines that are subject to the Standard. Documentation may include dated letters, e-mails, spreadsheets, etc.

Documenting Method of Identifying Sub-200kV Lines

R11. *Each Planning Coordinator shall develop and document its method for assessing the reliability significance of sub-200kV transmission lines whose loss would place the grid at an unacceptable risk of instability, separation, or cascading failures. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M11. *The Planning Coordinator has documented evidence such as planning study criteria or other analysis used to develop its method for assessing the reliability significance of sub-200kV lines whose loss would place the grid at an unacceptable risk of instability, separation, or cascading failures. (R11)*

Requirement R11 assigns to the Planning Coordinator the task of documenting its methods for assessing the reliability significance of sub-200kV lines. The methods and requirements for assessing significance of transmission lines are complex and spelled out in other prevailing NERC standards. Essentially, however, these methods include activities such as load flow studies, contingency analyses, and transient and dynamic voltage stability studies. Through the use of such studies, the significance of each transmission line to the reliability of the system is determined. Because such activities are already being conducted by the Planning Coordinator(s) to meet other standards, the Planning Coordinator may choose to adopt the same methods for meeting Requirement R11.

Appendix One: Clearance Distance Derivation by the Gallet Equation

The Gallet Equation is a well-known method of computing the required strike distance for proper insulation coordination, and has the ability to take into account various air gap geometries, as well as non-standard atmospheric conditions. When the Gallet Equation and conservative probabilistic methods are combined, i.e. deterministic design, sparkover probabilities of 10^{-6} or less are achieved. This approach is well known for its conservatism and was used to design the first 500kV and 765kV lines in North America [1]. Thus, the deterministic design approach using the Gallet Equation is used for the standard to compute the minimum strike distance between transmission lines and the vegetation that may be present in or along the transmission corridor.

Method Explanation (Gallet Equation)

In 1975 G. Gallet published a benchmark paper that provided a method to compute the critical flashover (CFO) voltage of various air gap geometries [4]. The Gallet Equation uses various “gap factors” to take into account various air gap geometries. Various gap factor values are provided in [1]. If the vegetation in a transmission corridor, e.g. a tree, is assumed electrically to be a large structure then the CFO of such an air gap geometry can be computed for dry or wet conditions using a well established equation proposed by Gallet [1],[2],[4],

$$CFO_A = k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} \tag{1}$$

Where:

k_w is defined as the factor that takes into account wet or dry conditions (dry = 1.0 and wet = 0.96) and phase arrangement (multiply by 1.08 for outside phase), e.g. outside phase and wet conditions = (0.96)(1.08) = 1.037,

k_g is defined as the gap factor (1.3 for conductor to large structure),

D is the strike distance (m),

CFO_A is the CFO for the relative air density (kV).

δ is defined as the relative air density and is approximately equal to (2) where A is the altitude in km,

$$\delta = e^{-\frac{A}{8.6}} \tag{2}$$

$$m = 1.25G_0\left(G_0 - 0.2\right) \tag{3}$$

$$G_0 = \frac{CFO_s}{500 \cdot D} \tag{4}$$

$$CFO_s = k_w \cdot k_g \cdot \frac{3400}{1+\frac{8}{D}} \tag{5}$$

Where CFO_S is the CFO for standard atmospheric conditions (kV). Using (1)-(5), the required CFO_A can be computed using an iterative process.

Once the CFO_A is known, deterministic methods can be used to determine the required clearance distance. If we let the maximum switching overvoltage be equal to the withstand voltage of the air gap (CFO_A - 3σ) then the CFO_A can be written as (6).

$$CFO_A = \frac{V_m}{1 - 3\left(\frac{\sigma}{CFO_A}\right)} \tag{6}$$

Where:

V_m is equal to the maximum switching overvoltage, i.e. the value that has a 0.135% chance of being exceeded,

σ is the standard deviation of the air gap insulation,

CFO_A is the critical flashover voltage of the air gap insulation under non-standard atmospheric conditions.

The ratio of σ to the CFO_A given in (6) can be assumed to be 0.05 (5%) [1]. Thus, (6) can be written as (7).

$$CFO_A = \frac{V_m}{0.85} \tag{7}$$

Substituting (7) into (1) we arrive at (8).

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1 + \frac{8}{D}} \tag{8}$$

Equation 8 relates the maximum transient overvoltage, V_m, to the air gap distance, D. Using (8) to compute the required clearance distance for the specified air gap geometry (conductor to large structure) results in a probability of flashover in the range of 10^{-6}.

Transient Overvoltage

In general, the worst case transient overvoltages occurring on a transmission line are caused by energizing or re-energizing the line with the latter being the extreme case if trapped charge is present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to sparkover from the line conductor to nearby vegetation. Thus, the worst case scenarios that are typically analyzed for insulation coordination purposes (e.g. line energization and re-energization) can be ignored. For the purposes of FAC-003-2, the worst case transient overvoltage then becomes the maximum value that can occur with the line energized. Determining a realistic value of transient overvoltage for this situation is difficult because the maximum transient overvoltage factors listed in the literature are based on a switching operation of the line in question. In other words, these maximum overvoltage values (e.g. the values listed in [2], [3] and [5]) are based on the assumption that the subject line is being energized, re-energized or de-energized. These operations, by their very nature, will create the largest transient overvoltages. Typical values of transient overvoltages of in-service lines, as such, are not readily available in the literature because the resulting level of overvoltage is negligible compared with the maximum (e.g. re-energizing a transmission line with trapped charge). A conservative value for the maximum transient overvoltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 p.u.[2]. This value is a conservative estimate of the transient overvoltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without a pre-insertion device (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. 362kV), the maximum transient overvoltage of an "in-service" ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 p.u. or less [2]. It is well known that these theoretical transient overvoltages will not be experienced at locations remote from the bus at which they were created; however, in order to be conservative, it will be assumed that all nearby ac lines are subjected to this same level of overvoltage. Thus, a maximum transient overvoltage factor of 2.0 p.u. for 242 kV and below and 1.4 p.u. for ac transmission lines 362 kV and above is used to compute the required clearance distances for vegetation management purposes.

The overvoltage characteristics of dc transmission lines vary somewhat from their ac counterparts. The referenced empirically derived transient overvoltage factor used to calculate the minimum clearance distances from dc transmission lines to vegetation for the purpose of FAC-003-2 will be 1.8 p.u.[3].

Example Calculation

An example calculation is presented below using the proposed method of computing the vegetation clearance distances. It is assumed that the line in question has a maximum operating voltage of 550 kV_{rms} line-to-line. Using a per unit transient overvoltage factor of 1.4, the result is a peak transient voltage of 629 kV_{crest}. It is further assumed that the line in question operates at a maximum altitude of 7000 feet (2.134 km) above sea level.

The required withstand voltage of the air gap must be equal to or greater than 629 kV_{crest}. Since the altitude is above sea level, (1) - (5) have to be iterated on to achieve the desired result. Equation (9) can be used as an initial guess for the clearance distance.

$$D_i = \frac{8}{\dfrac{3400 \cdot k_w \cdot k_g}{\left(\dfrac{V_m}{0.85}\right)} - 1} \tag{9}$$

For our case here, V_m is equal to 629 kV, k_w = 1.037 and k_g = 1.3. Thus,

$$D_i = \frac{8}{\dfrac{3400 \cdot k_w \cdot k_g}{\left(\dfrac{V_m}{0.85}\right)} - 1} = \frac{8}{\dfrac{3400 \cdot 1.037 \cdot 1.3}{\left(\dfrac{629}{0.85}\right)} - 1} = 1.535m \tag{10}$$

Using (2)-(5) and (8) the withstand voltage of the air gap is next computed. This value will then be compared to the maximum transient overvoltage.

$$CFO_S = k_w \cdot k_g \cdot \frac{3400}{1 + \dfrac{8}{D}} = 1.037 \cdot 1.3 \cdot \frac{3400}{1 + \dfrac{8}{1.535}} = 737.7kV \tag{11}$$

$$\delta = e^{-\frac{A}{8.6}} = e^{-\frac{2.134}{8.6}} = 0.78 \tag{12}$$

$$G_O = \frac{CFO_S}{500 \cdot D} = \frac{737.7}{(500)\cdot(1.535)} = 0.961 \tag{13}$$

$$m = 1.25 \cdot G_O(G_O - 0.2) = 1.25 \cdot 0.961(0.961 - 0.2) = 0.915 \tag{14}$$

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} = (0.85)(1.037)(1.3)(0.78)^{0.915}\left(\frac{3400}{1+\frac{8}{1.535}}\right) = 499.8kV \tag{15}$$

The calculated V_m is less than 629 kV; thus, the clearance distance must be increased. A few iterations using (2)-(5) and (8) are required until the computed $V_m \geq 629$ kV. For this case it was found that D = 1.978 m (6.49 feet) yielded V_m = 629.3kV. Using this clearance distance the following values were computed for the final iteration.

$$CFO_S = k_w \cdot k_g \cdot \frac{3400}{1+\frac{8}{D}} = 1.037 \cdot 1.3 \cdot \frac{3400}{1+\frac{8}{1.978}} = 908.5kV \tag{16}$$

$$\delta = e^{-\frac{A}{8.6}} = e^{-\frac{2.134}{8.6}} = 0.78 \tag{17}$$

$$G_O = \frac{CFO_S}{500 \cdot D} = \frac{908.5}{(500)\cdot(1.978)} = 0.919 \tag{18}$$

$$m = 1.25 \cdot G_O(G_O - 0.2) = 1.25 \cdot 0.919(0.919 - 0.2) = 0.825 \tag{19}$$

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} = (0.85)(1.037)(1.3)(0.78)^{0.825}\left(\frac{3400}{1+\frac{8}{1.978}}\right) = 629.3kV \tag{20}$$

Therefore, the minimum vegetation clearance distance for a maximum line to line ac operating voltage of 550 kV at 7000 feet above sea level is 1.978 m (6.49 feet). Table 1 provides calculated distances for various altitudes and maximum system operating ac voltages.

TABLE 1 — Minimum Vegetation Clearance Distances (MVCD)
For **Alternating Current** Voltages

(AC) Nominal System Voltage (kV)	(AC) Maximum System Voltage (kV)	MVCD feet (meters) Sea level	MVCD feet (meters) 3,000ft (914.4m)	MVCD feet (meters) 4,000ft (1219.2m)	MVCD feet (meters) 5,000ft (1524m)	MVCD feet (meters) 6,000ft (1828.8m)	MVCD feet (meters) 7,000ft (2133.6m)	MVCD feet (meters) 8,000ft (2438.4m)	MVCD feet (meters) 9,000ft (2743.2m)	MVCD feet (meters) 10,000ft (3048m)	MVCD feet (meters) 11,000ft (3352.8m)
765	800	8.06ft (2.46m)	8.89ft (2.71m)	9.17ft (2.80m)	9.45ft (2.88m)	9.73ft (2.97m)	10.01ft (3.05m)	10.29ft (3.14m)	10.57ft (3.22m)	10.85ft (3.31m)	11.13ft (3.39m)
500	550	5.06ft (1.54m)	5.66ft (1.73m)	5.86ft (1.79m)	6.07ft (1.85m)	6.28ft (1.91m)	6.49ft (1.98m)	6.7ft (2.04m)	6.92ft (2.11m)	7.13ft (2.17m)	7.35ft (2.24m)
345	362	3.12ft (0.95m)	3.53ft (1.08m)	3.67ft (1.12m)	3.82ft (1.16m)	3.97ft (1.21m)	4.12ft (1.26m)	4.27ft (1.30m)	4.43ft (1.35m)	4.58ft (1.40m)	4.74ft (1.44m)
230	242	2.97ft (0.91m)	3.36ft (1.02m)	3.49ft (1.06m)	3.63ft (1.11m)	3.78ft (1.15m)	3.92ft (1.19m)	4.07ft (1.24m)	4.22ft (1.29m)	4.37ft (1.33m)	4.53ft (1.38m)
161*	169	2ft (0.61m)	2.28ft (0.69m)	2.38ft (0.73m)	2.48ft (0.76m)	2.58ft (0.79m)	2.69ft (0.82m)	2.8ft (0.85m)	2.91ft (0.89m)	3.03ft (0.92m)	3.14ft (0.96m)
138*	145	1.7ft (0.52m)	1.94ft (0.59m)	2.03ft (0.62m)	2.12ft (0.65m)	2.21ft (0.67m)	2.3ft (0.70m)	2.4ft (0.73m)	2.49ft (0.76m)	2.59ft (0.79m)	2.7ft (0.82m)
115*	121	1.41ft (0.43m)	1.61ft (0.49m)	1.68ft (0.51m)	1.75ft (0.53m)	1.83ft (0.56m)	1.91ft (0.58m)	1.99ft (0.61m)	2.07ft (0.63m)	2.16ft (0.66m)	2.25ft (0.69m)
88*	100	1.15ft (0.35m)	1.32ft (0.40m)	1.38ft (0.42m)	1.44ft (0.44m)	1.5ft (0.46m)	1.57ft (0.48m)	1.64ft (0.50m)	1.71ft (0.52m)	1.78ft (0.54m)	1.86ft (0.57m)
69*	72	0.82ft (0.25m)	0.94ft (0.29m)	0.99ft (0.30m)	1.03ft (0.31m)	1.08ft (0.33m)	1.13ft (0.34m)	1.18ft (0.36m)	1.23ft (0.37m)	1.28ft (0.39m)	1.34ft (0.41m)

*As designated by the Planning Coordinator

TABLE 1 (CONT.) — Minimum Vegetation Clearance Distances (MVCD)
For **Direct Current** Voltages

(DC) Nominal Pole to Ground Voltage (kV)	MVCD feet (meters) sea level	MVCD feet (meters) 3,000ft (914.4m) Alt.	MVCD feet (meters) 4,000ft (1219.2m) Alt.	MVCD feet (meters) 5,000ft (1524m) Alt.	MVCD feet (meters) 6,000ft (1828.8m) Alt.	MVCD feet (meters) 7,000ft (2133.6m) Alt.	MVCD feet (meters) (8,000ft (2438.4m) Alt.	MVCD feet (meters) 9,000ft (2743.2m) Alt.	MVCD feet (meters) 10,000ft (3048m) Alt.	MVCD feet (meters) 11,000ft (3352.8m) Alt.
±750	13.92ft (4.24m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.9ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.07ft (3.07m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	(13.54ft 4.13m)
±500	7.89ft (2.40m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	4.78ft (1.46m)	5.35ft (1.63m)	5.55ft (1.69m)	5.75ft (1.75m)	5.95ft (1.81m)	6.15ft (1.87m)	6.36ft (1.94m)	6.57ft (2.00m)	6.77ft (2.06m)	6.98ft (2.13m)
±250	3.43ft (1.05m)	4.02ft (1.23m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5ft (1.52m)	5.17ft (1.58m)

List of Acronyms and Abbreviations

AC	Alternating Current
ANSI	American National Standards Institute
CFO	Critical Flashover
DC	Direct Current
IEEE	Institute of Electrical and Electronics Engineers
IROL	Interconnection Reliability Operating Limit
IVM	Integrated Vegetation Management
NERC	North American Electric Reliability Corporation
IROL	Interconnection Reliability Operating Limit
MVCD	Minimum Vegetation Clearance Distance
TGR	Tree Growth Regulator
TO	Transmission Owner
TVMP	Transmission Vegetation Management Program
WECC	Western Electricity Coordinating Council

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Implementation Plan for FAC-003-2

Prerequisite Approvals
There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

FAC-003-2 — Vegetation Management

Revision to Approved Standards and Definitions
There are no proposed revisions to requirements in other already approved standards associated with the approval of FAC-003-2.

The drafting team is proposing the following changes to definitions:

- **Retire the existing approved definition for "Vegetation Inspection:"**
  The systematic examination of a transmission corridor to document vegetation conditions.
- **Implement a new definition for "Vegetation Inspection:"**
  The systematic examination of vegetation conditions on an Active Transmission Line Right of Way. This inspection may be combined with a general line inspection. The inspection includes the documentation of any vegetation that may pose a threat to reliability prior to the next planned inspection or maintenance work, considering the current location of the conductor and other possible locations of the conductor due to sag and sway for rated conditions.
- **Implement a new definition for "Active Transmission Line Right of Way:"**
  A strip of land that is occupied by active transmission facilities. This corridor does not include the inactive or unused part of the Right of Way intended for other facilities.

FAC-003-1 and the existing definition of "Vegetation Inspection" will be retired and the new definitions for "Vegetation Inspection" and "Active Transmission Line Right of Way" will become effective at the same time that FAC-003-2 becomes effective.

Compliance with Standard
The standard applies to Transmission Owners and Planning Coordinators.

Effective Date
The effective date is the date entities are expected to meet the performance identified in this standard. The effective date (for all requirements), for jurisdictions where regulatory approval is required, is the first calendar day of the first calendar quarter one year after applicable regulatory authority. The effective date (for all requirements), for jurisdictions where no regulatory approval is required, is the first calendar day of the first calendar quarter one year following Board of Trustees adoption. The effective date allows the Planning Coordinator time to conduct the analyses needed to identify sub-200kV transmission lines that should be subject to this standard.

Standards Announcement

Comment Period Open
September 9–October 24, 2009

Now available at: http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

Project 2007-07: Transmission Vegetation Management

The Transmission Vegetation Management Standard Drafting Team is seeking comments on the following documents **until 8 p.m. EDT on October 24, 2009**:

- FAC-003-2 — Transmission Vegetation Management Program
- Mapping document (comparing FAC-003-1 to FAC-003-2)
- Implementation plan for FAC-003-2
- Technical reference document

This is the second comment period for proposed standard FAC-003-2. The drafting team revised the proposed standard, updated the technical reference document to align with the changes made to the proposed standard, updated the mapping document, and added an implementation plan. The drafting team has also posted its consideration of industry comments received during the previous comment period.

Instructions

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at Lauren.Koller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page: http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

Next Steps

The drafting team will draft and post responses to comments received during this period. The drafting team will also determine whether to post the standard for an additional comment period or seek approval from the Standards Committee to proceed to balloting.

Project Background

The project is an update to FAC-003-1, which was approved in 2006. The items identified for revision include the incorporation of FERC Order 693 comments related to applicability, procedural repairs to conform to the current standards format and development procedure, technical updates and guidance to address stakeholder suggestions, and the elimination of "fill-in-the-blank" components. More information is available on the project page.

Applicability of Standards in Project

Transmission Owner
Planning Coordinator
Specific facilities (see proposed standard for more information)

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Vegetation Management FAC-003-2 Standard — Project 2007-07

The Vegetation Management Standard Drafting Team thanks all commenters who submitted comments on the proposed FAC-003-2 — Transmission Vegetation Management Standard. This standard was posted for a 30-day public comment period from September 10, 2009 through October 24, 2009. The stakeholders were asked to provide feedback on the standard through a special Electronic Comment Form. There were 66 sets of comments, including comments from 156 different people from more than 85 companies representing all of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

On January 14, 2010, the NERC Standards Committee endorsed the use of Project 2007-07 Vegetation Management as the prototype for the proof-of-concept for using the results-based criteria for developing a reliability standard. The results-based initiative is intended to focus the collective effort of NERC and industry participants on improving the clarity and quality of NERC reliability standards by developing performance, risk and competency-based requirements that accomplish a reliability objective through a defense-in-depth strategy, while eliminating documentation-driven requirements that do not have an impact on bulk power system reliability.

The Standards Committee directed the Vegetation Management SDT to stop work in refining its second draft of the Vegetation Management standard but to inform stakeholders on how the team had used stakeholder comments to refine the technical requirements carried over into draft 3 of the standard. The drafting team did not develop individual responses to the comments submitted by stakeholders on the second draft of FAC-003-2. Instead, the drafting team produced a special summary report that shows all the questions asked and provides a summary indicating how the drafting team used stakeholder comments submitted in response to that question. The special report is posted on the FAC-003 project page identified in the URL above under the title, “Summaries.”

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Richard Kafka	Pepco Holdings, Inc - Affiliates (PHI)	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Pat Byrne	Potomac Electric Power Company	RFC	1
2. Dave Paduda	Potomac Electric Power Company	RFC	1
3. Steve Benn	Delmarva Power & Light	RFC	1
4. Olivia Watts	Atlantic City Electric	RFC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Guy Zito	Northeast Power Coordinating Council--RSC										X

Additional Member	Additional Organization	Region	Segment Selection
1. Ralph Rufrano	New York Power Authority	NPCC	5
2. Alan Adamson	New York State Reliability Council, LLC	NPCC	10
3. Gregory Campoli	New York Independent System Operator	NPCC	2
4. Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
5. Kurtis Chong	Independent Electricity System Operator	NPCC	2
6. Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Saurabh Saksena		National Grid	NPCC					1				
8.	Chris de Graffenried		Consolidated Edison Co. of New York, Inc.	NPCC					1				
9.	Brian D. Evans-Mongeon		Utility Services	NPCC					8				
10.	Mike Garton		Dominion Resources Services, Inc.	NPCC					5				
11.	Brian L. Gooder		Ontario Power Generation Incorporated	NPCC					5				
12.	Kathleen Goodman		ISO - New England	NPCC					2				
13.	David Kiguel		Hydro One Networks Inc.	NPCC					1				
14.	Michael R. Lombardi		Northeast Utilities	NPCC					1				
15.	Randy MacDonald		New Brunswick System Operator	NPCC					2				
16.	Greg Mason		Dynegy Generation	NPCC					5				
17.	Bruce Metruck		New York Power Authority	NPCC					6				
18.	Chris Orzel		FPL Energy/NextEra Energy	NPCC					5				
19.	Robert Pellegrini		The Untied Illuminating Company	NPCC					1				
20.	Michael Schiavone		National Grid	NPCC					1				
21.	Peter Yost		Consolidated Edison Co. of New York, Inc.	NPCC					3				
22.	Gerry Dunbar		Northeast Power Coordinating Council	NPCC					10				
23.	Lee Pedowicz		Northeast Power Coordinating Council	NPCC					10				
3.	Group	Jim Butler	Public Service Co. of New Mexico	X									
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Anne Beard		PNM	WECC					1				
4.	Group	Deborah Schaneman	Platte River Power Authority Vegetation Management Group	X		X		X					
	Additional Member		Additional Organization	Region					Segr				
1.	Scott Rowley		Platte River Power Authority	WECC					1, 3, 5				
2.	Gary Whittenberg		Platte River Power Authority	WECC					1, 3, 5				
5.	Group	John Neagle	Associated Electric Cooperative, Inc.	X				X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chris Bolick	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
2.	John Bussman	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
3.	Kevin Hopper	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
4.	Jeff Neas	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
5.	Gary Highfill	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
6.	Ted Hilmes	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
7.	David McDowell	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
8.	Bill Price	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
9.	Bob Schreiner	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
10.	Ralph Schulte	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
11.	John Settle	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
12.	John Stickley	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
13.	Craig Thomas	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
14.	Kevin White	Associated Electric Cooperative, Inc.	SERC	1, 5, 6

6.	Group	Joe Spencer	SERC Vegetation Management Sub-committee (VMS)										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Randy Gann	Alabama Power Company	SERC	1, 3, 5
2.	Jeffrey Hackman	Ameren Services Company	SERC	1, 3, 5
3.	Gerald Beckerle	Ameren Services Company	SERC	1, 3, 5
4.	John Neagle	Associated Electric Cooperative, Inc.	SERC	1, 3, 5, 6
5.	Billy George	Duke Energy Carolinas	SERC	1, 3, 5, 6
6.	Robert Trimble	E.ON U.S. Services Inc. for LG&E & KU Companies	SERC	1, 3, 5, 6
7.	Ralph Hale	Entergy	SERC	1, 3, 5, 6
8.	Jim Case	Entergy	SERC	1, 3, 5, 6
9.	Marc Tunstall	Fayetteville Public Works Commission	SERC	1, 3

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
10.	Reggie Wallace		Fayetteville Public Works Commission	SERC					1, 3				
11.	Terry Wilson		PowerSouth Energy Cooperative	SERC					6, 1, 3, 5				
12.	Jack Gardner		Progress Energy Carolinas	SERC					1, 3, 5, 6				
13.	Jerry Lindler		South Carolina Electric & Gas Company	SERC					1, 3, 5, 6				
14.	Richard Dearman		Tennessee Valley Authority	SERC					1, 3, 5, 9				
15.	Ron Adams		Duke Energy Carolinas	SERC					1, 3, 5, 6				
16.	Joe Spencer		SERC Reliability Corp.	SERC					10				
17.	Dane Jonas (VMS visitor)		Va. Electric and Power Co.	SERC					1, 3, 5				
7.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				
	Additional Member		Additional Organization	Region					Segment Selection				
1.	John Jamrog		Transmission Vegetation/Access Road Mgmt	WECC					1				
2.	Mike Staats		Transmission Engineering	WECC					1				
3.	Jerry Reding		Transmission Line Design	WECC					1				
4.	Marian Wolcott		Transmission Real Property Services	WECC					1				
5.	Jennifer Bailey		Transmission TLM Technical Svcs	WECC					1				
6.	Berhanu Tesema		Transmission Planning	WECC					1				
7.	Mark Newbil		Transmission Vegetation/Access Road Mgmt	WECC					1				
8.	Mike Viles		Transmission Technical Operations	WECC					1				
9.	Dan Tuominen		Transmission Line Design	WECC					1				
10.	Steve Narolski		Transmission Vegetation/Access Road Mgmt	WECC					1				
11.	Frank Weintraub		Transmission Line Design	WECC					1				
12.	Allen Chan		Office of General Counsel	WECC					1				
8.	Group	Doug Hohlbaugh	FirstEnergy Corp	X		X	X	X	X				
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Rebecca Spach		FE	RFC					1				
2.	Shawn Standish		FE	RFC					1				
3.	Katrina Schnobrich		FE	RFC					1				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
4. Mike Ferncez			FE	RFC					1				
5. Sam Ciccone			FE	RFC					1, 3, 4, 5, 6				
6. David Folk			FE						1, 3, 4, 5, 6				
9.	Group	Carol Gerou	NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Neal Balu	WPS Corporation	MRO	3, 4, 5, 6
2.	Terry Bilke	Midwest ISO Inc.	MRO	2
3.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
4.	Ken Goldsmith	Alliant Energy	MRO	4
5.	Alice Murdock	Xcel Energy	MRO	1, 3, 5, 6
6.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
7.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
8.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
9.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
10.	Scott Nickels	Rochester Public Utilties	MRO	4
11.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Ben Li	ISO/RTO Council		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charles Yeung	SPP	SPP Region	2
2.	Matt Goldberg	ISO-NE	NPCC Region	2
3.	Patrick Brown	PJM	RFC Region	2
4.	Bill Phillips	MISO	MRO Region	2
5.	James Castle	NYISO	NPCC Region	2
6.	Steve Myers	ERCOT	ERCOT Region	2
7.	Mark Thompson	AESO	WECC Region	2
8.	Lourdes Estrada-Salinero	CAISO	WECC Region	2

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
11.	Individual	Chip Turner	Tampa Electric Company	X		X		X					
12.	Individual	Michael Davis	WECC RC										X
13.	Individual	Tom Glock-	Arizona Public Service	X		X	X	X		X	X		
14.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
15.	Individual	Derek Vannice	Utility Arborist Association										
16.	Individual	Mary Hetz	Ameren	X									
17.	Individual	Jim Fulton	Vegetation Management Team	X									
18.	Individual	Brent Ingebrigtson	E.ON U.S.	X		X		X	X				
19.	Individual	Silvia Parada-Mitchell	Transmission Owner	X				X	X				
20.	Individual	Hugh Francis	Southern Company	X		X		X					
21.	Individual	James P. Fama	Edison Electric Institute	X									
22.	Individual	Jody Nelson	Georgia Transmission Corporation	X									
23.	Individual	Frank Gaffney	Florida Municipal Power Agency, and its Member Cities, Lakeland Electric and Kissimmee Utility Authority	X		X	X	X	X				
24.	Individual	Linwood Blacksmith	Superintendent Transmission Maintenance	X		X		X					
25.	Individual	Weston Davis	Central Maine Power an Energy East Company	X									

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
26.	Individual	James Starling	SCE&G	X		X		X	X				
27.	Individual	Anthony Johnson	Northeast Utilities	X									
28.	Individual	Thomas E. Sullivan	National Grid	X		X							
29.	Individual	Virginia Cook	JEA	X		X		X					
30.	Individual	Richard Dearman	TVA	X	X			X					
31.	Individual	Pat Simons	Idaho Power Company	X									
32.	Individual	Diana Gilman	Lee County Electric Cooperative	X									
33.	Individual	Stephen Tankersley	Pacific Gas and Electric Co.	X		X		X					
34.	Individual	James Manning	North Carolina Electric Membership Corporation			X	X	X					
35.	Individual	James H. Sorrels, Jr.	American Electric Power	X		X		X	X				
36.	Individual	Gwen shrimpton	BC Transmission Corporation	X									
37.	Individual	Larry Akens	TVA	X									
38.	Individual	Rao Somayajula	ReliabilityFirst Corporation										X
39.	Individual	Ian S Grant	Tennessee Valley Authority	X		X		X				X	
40.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
41.	Individual	ron turley	Western Area Power Administration, Rocky Mountain Region	X								X	

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
42.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
43.	Individual	Doug Bailey	TVA	X		X						X	
44.	Individual	Alice Murdock	Xcel Energy	X		X		X	X				
45.	Individual	Patricia Metro	NRECA - National Rural Electric Cooperative Association			X	X						
46.	Individual	Larry Rodriguez	Entegra Power Group LLC					X					
47.	Individual	David Kiguel	Hydro One Networks inc.	X		X							
48.	Individual	Edward Bedder	Orange and Rockland Utilities, Inc.	X									
49.	Individual	Brian Scott	New Brunswick Power Transmission	X									
50.	Individual	Michael Pakeltis	CenterPoint Energy	X									
51.	Individual	John Humphrey	Nebraska Public Power District	X		X		X					
52.	Individual	Darryl Curtis	Oncor Electric Delivery	X									
53.	Individual	Ed Davis	Entergy Services, Inc	X		X		X	X				
54.	Individual	Russell Hardison	Tennessee Valley Authority	X	X			X				X	
55.	Individual	Kathleen Goodman	ISO New England Inc.		X								
56.	Individual	Martin Bauer	US Bureau of Reclamation					X					
57.	Individual	Jason Shaver	American Transmission Company	X									

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
58.	Individual	Jack Gardner	Progress Energy Carolinas, Inc.	X		X		X	X				
59.	Individual	Gary Cox	Tucson Electric Power Company	X		X							
60.	Individual	Patrick Farrell	Southern California Edison Company	X		X		X	X				
61.	Individual	Karen Powell	Salt River Project	X		X		X	X				
62.	Individual	Steve Rueckert	WECC										X
63.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									
64.	Individual	Dan Rochester	Independent Electricity System Operator		X								
65.	Individual	George Czerniewski	Consolidated Edison Company of New York Inc.	X									
66.	Individual	Catherine Koch	Puget Sound Energy	X									
67.	Individual	Jason Lietz	Northern Indiana Public Service Company	X									

1. As stated in the background information above, in response to industry comments, the Requirement for documentation of a TVMP (the new R1) is revised. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Summary Consideration:

Organization	Yes or No	Question 1 Comment
Entegra Power Group LLC		No comment
American Electric Power	Agree	
Associated Electric Cooperative, Inc.	Agree	
BC Transmission Corporation	Agree	
Bonneville Power Administration	Agree	
Duke Energy	Agree	
Entergy Services, Inc	Agree	
Georgia Transmission Corporation	Agree	
Hydro One Networks inc.	Agree	
New Brunswick Power Transmission	Agree	
North Carolina Electric Membership Corporation	Agree	
Northeast Utilities	Agree	

Organization	Yes or No	Question 1 Comment
Pacific Gas and Electric Co.	Agree	
ReliabilityFirst Corporation	Agree	
SCE&G	Agree	
SERC Vegetation Managment Sub-committee (VMS)	Agree	
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tampa Electric Company	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Tucson Electric Power Company	Agree	
TVA	Agree	
TVA	Agree	
TVA	Agree	
US Bureau of Reclamation	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain	Agree	

Organization	Yes or No	Question 1 Comment
Region		
Orange and Rockland Utilities, Inc.	Agree	Although ORU agrees that each TO should be required to have a documented TVMP, we recommend changing the wording in Sections 1.2 and 1.3.2.In Section 1.2, ORU recommends the wording to read, ‘Specify a Vegetation Inspection of at least once per calendar year.’ The additional wording regarding local and environmental factors may cause unnecessary confusion for some. In Section 1.3.2, the phrase ‘...and methods to be used...’ should be changed to read, ‘...and methods that may be used....’ to be consistent with the wording in Section 1.1. Also, the terms ‘operating range’ and ‘rated conditions’ in R1.6 should be clearly defined in the Standard and added to the NERC Glossary to avoid confusion.
Southern California Edison Company	Agree	Comments: SCE appreciates and agrees with the Drafting Team’s efforts and approach to revising R1. We agree with the assignment of a Violation Risk Factor of “Lower.” However, we would like to suggest certain revisions (included below) for the sake of clarity.R1. Each Transmission Owner shall institute a documented transmission vegetation management program that describes how it conducts work on its Active Transmission Line Rights of Way to prevent Sustained Outages due to vegetation, considering all possible locations the conductor may occupy under the effects of sag and sway throughout its operating range under rated conditions. The transmission vegetation management program shall specify: [Violation Risk Factor - Lower][Time Horizon -Long-term planning]1.1. The methodologies methods that the Transmission Owner may use to control vegetation.1.2. A Vegetation Inspection frequency of at least once per calendar year that takes into account local and environmental factors.1.3. An annual work plan that identifies:1.3.1. The applicable lines to be maintained.1.3.2. The work to be performed and methods to be used.1.3.3. Sufficient flexibility to adjust to changing conditions and to findings from Vegetation Inspections. Adjustments to the plan within the year are permissible. 1.3.4. Necessary permitting and scheduling requirements from landowners or regulatory authorities. 1.4. A process or procedure for responding to an imminent threat of a vegetation related Sustained Outage. The process or procedure shall specify actions that include communication of the threat to the responsible control center.1.5. An interim corrective action process for use when the Transmission Owner is constrained from performing planned vegetation maintenance. 1.6. The maintenance strategies used (such as minimum vegetation-to- conductor distance or maximum vegetation height) to ensure that Table 1 clearances in Attachment 1 are never violated. The maintenance strategies shall consider the sag and sway of the conductor throughout its operating range under rated conditions.
Edison Electric Institute	Agree	EEI generally agrees with changes to draft revised R1. In addition, EEI recommends that the SDT consider an alternative structure for the wording of R 1.6, where the current wording states ‘...specify...maintenance strategies ... to ensure that Table 1 clearances are never violated.’ To improve clarity and better reflect the intent for this requirement as stated in the Technical Paper, EEI suggests consideration of the language directly from the Technical Paper (p. 24). Thus, the requirement could be edited to state: “Maintenance strategies must be designed to a) meet the Table 1 clearances in Attachment 1 and b) consider all possible

Organization	Yes or No	Question 1 Comment
		locations of the conductor for rated design conditions." Companion M 1.6 could be revised to state: "Transmission Owner has evidence of its consideration of the range of all possible positions of conductors and line loading variables."FERC Order No. 693 does not direct NERC to establish minimum inspection cycles. Rather, FERC stated a goal for the Standard to '...assure that transmission owners conduct inspections at reasonable intervals.' (Order 693, P. 720) EEI recommends the SDT consider an alternative to the proposed annual inspection minimum requirement. In some regions of North America for some companies, or for parts of service territories for some companies, inspections for vegetation issues are irrelevant, or, needed significantly less frequently than an annual basis. At the other end of the spectrum, a company-wide annual requirement could inadvertently 'lower the bar.' On either side of the spectrum, a 'one size fits all' approach may have unintended consequences that challenge the ability for companies to maintain realistic inspection cycles. Therefore, EEI recommends that the SDT consider an alternative to R 1.2 to state that descriptions of inspection cycle frequencies should be included in the vegetation management program annual plan under R 1.3, including reasoning for inspection frequency basis. Should the SDT choose to not revise this requirement, EEI notes that provisions of the Standards Development Procedures manual, both for entity variance and regional variance for an area less than an Interconnection in size (Standards Development Procedures, p. 27), may be an alternative to the extent that vegetation issues within a company service territory, or a geographic area that includes parts of several company service territories, reflect conditions that do not require performance at the level stated within a requirement.Revised draft R 1.6 states that maintenance strategies in companies' vegetation management programs must consider 'sag and sway of the conductor throughout its operating range under rated conditions.'Since neither 'operating range' nor 'rated conditions' are defined NERC terms, this requirement could be open to broad interpretation. As a result, EEI recommends that the SDT consider alternatives that will reduce potential ambiguity. FAC-003 currently requires Clearance 2 to be maintained for 'all rated electrical operating conditions.' This suggests to EEI that vegetation clearances should be set in a manner such that required clearances will be maintained for conditions that include line loadings at both Normal and Emergency Ratings. EEI recommends that the SDT consider additional specificity. If the term 'operating range under rated conditions' is retained, it should be clearly defined. For example, the Requirement could include explicit references to Normal Ratings and Emergency Ratings used in other FAC -class Standards, coupled with a Measurement that a Registered Entity can demonstrate that Ratings applied to FAC-003 are the same as those used elsewhere.
National Grid	Agree	National Grid encourages the drafting team to leave the reference to A.N.S.I. A300 in the standard.
PacifiCorp	Agree	PacifiCorp thinks it is very important for improved reliability to directly reference ANSI A300, rather than relegate it to a footnote. ANSI A300 is science-based, and proven to be effective. Directly referencing adherence to A300 will encourage uniform compliance with FAC-003 across North America. Without this reference, PacifiCorp fears grid stability could be threatened by ineffective practices applied by utilities that lack sufficient expertise to manage their systems. PacifiCorp believes that those utilities could create future

Organization	Yes or No	Question 1 Comment
		blackouts due simply to a lack of understanding about proper utility vegetation management practices. Consequently, PacifiCorp urges direct reference to A300 within the standard. PacifiCorp believes eliminating clearance 1 will be detrimental to reliability. Clearance 1 is important for utilities to account for the dynamics of conductor movement and vegetative growth. This required analysis should lead to development of a more informed vegetation management program. Clearance 1 also gives utilities leverage with landowners, governmental agencies and local regulators to achieve the necessary operational clearances. If the only required clearance is the R4 Minimum Vegetation Clearance Distance, landowners and local regulators will push the utility to maintain a little more than those clearances rather than properly taking tree growth into account.
Pepco Holdings, Inc - Affiliates (PHI)	Agree	PHI understands that the SDT was responding to FERC Order 693, but feels there has been a one-size-fits-all approach. An approach as taken in PRC-005 could be used whereby the Transmission Owner could state its basis for vegetation maintenance cycles.Neither -operating range- nor -rated conditions- are defined NERC terms; this requirement could be open to broad interpretation. As a result, PHI recommends that the SDT consider alternatives that will reduce potential ambiguity. FAC-003 currently requires Clearance 2 to be maintained for -all rated electrical operating conditions-. This suggests that vegetation clearances should be set in a manner such that required clearances will be maintained for conditions that include line loadings at both Normal and Emergency Ratings. PHI recommends that the SDT consider additional specificity.
Xcel Energy	Disagree	(a) The requirement in R1.2 that mandates an annual inspection is too onerous. Xcel Energy urges the retention of the provision in the existing standard that allows the Transmission Owner to set the frequency of inspection. In some areas of the country, annual inspections may not be adequate. Yet in other areas, a longer inspection frequency may be perfectly reasonable and practical. Our point is that inspection frequency should not be treated as if it were “one size fits all”. If treated this way, we feel this could pose a risk to reliability and is not likely to be cost-effective. The Transmission Owner should be allowed some flexibility. However, if the drafting team disagrees and determines that an annual inspection is to be mandated, Xcel Energy believes that an exception to the annual inspection is appropriate when a non-subjective advanced technology such as LIDAR is utilized to achieve actual clearance distances. This places the Transmission Owner in a situation where it can rationally determine that the objectively measured distances result in a situation where an inspection need not be performed within the next year. It is suggested that R1.2 be revised to read as follows: Specify a Vegetation Inspection frequency of at least once per calendar year that takes into account local and environmental factors, unless the Transmission Owner, based on a non-subjective advanced technology, such as LIDAR, determines that a longer inspection period is appropriate.(b) R1.5: the word “temporarily” needs to be removed. Some constraints are not of a temporary nature. One example would be the U.S. Forest Service’s refusal to allow trimming or removal in accordance with the Transmission Owner’s vegetation management guidelines; another exists in the case where the easement or other instrument allowing the Transmission Owner to occupy the land does not allow vegetation management

Organization	Yes or No	Question 1 Comment
		in accordance with the Transmission Owner guidelines. In such situations, an interim corrective action process is appropriate but the word “temporarily” is not.(c) Section R1.6 should be reworded. The existing language is troublesome and confusing. A better alternative would be: "Maintenance strategies must be designed to (a) meet the table 1 clearances in attachment 1, and (b) consider all possible locations of the conductor for rated design conditions."
MRO NERC Standards Review Subcommittee	Disagree	A. The requirement in R1.2 that mandates an annual inspection is too onerous. The MRO NSRS urges the retention of the provision in the existing standard that allows the Transmission Owner to set the frequency of inspection. In some areas of the country, annual inspections may not be adequate. Yet in other areas, a longer inspection frequency may be perfectly reasonable and practical. Our point is that inspection frequency should not be treated as if it were “one size fits all”. If treated this way, the MRO NSRS feels this could pose a risk to reliability and is not likely to be cost-effective. The Transmission Owner should be allowed some flexibility. However, if the drafting team disagrees and determines that an annual inspection is to be mandated, the MRO NSRS believes that an exception to the annual inspection is appropriate when a non-subjective advanced technology such as LIDAR is utilized to achieve actual clearance distances. This places the Transmission Owner in a situation where it can rationally determine that the objectively measured distances result in a situation where an inspection need not be performed within the next year. Additionally, the MRO NSRS feels “that takes into account local and environmental factors” is explanatory text and is inappropriate for a requirement. It is suggested that R1.2 be revised to read as follows: Specify a Vegetation Inspection frequency of at least once per calendar year, unless the Transmission Owner, based on a non-subjective advanced technology, such as LIDAR, determines that a longer inspection period is appropriate.B. R1.5: the word “temporarily” needs to be removed. Some constraints are not of a temporary nature. For example, the U.S. Forest Service’s refusal to allow trimming or removal in accordance with the Transmission Owner’s vegetation management guidelines, or in the case where the easement or other instrument allowing the Transmission Owner to occupy the land does not allow vegetation management in accordance with the Transmission Owner guidelines. In such a situation, an interim corrective action process is appropriate but the word “temporarily” is not. What happens if it’s more than “temporarily”?C. R1.6 should be reworded. The existing language is troublesome and confusing. A better alternative would be: "Maintenance strategies must be designed to (a) meet the table 1 clearances in attachment 1, and (b) consider all possible locations of the conductor for rated design conditions." D. R1.3.3 states that the annual work plan shall....”Be flexible to adjust to changing conditions and to findings from Vegetation Inspections. Adjustments to the plan within the year are permissible.” The MRO NSRS is concerned that the wording would not allow a situation where the work plan is not entirely implemented “within the year”. There may be instances where you may be justified to postpone the work planned at the end of the year and must be moved into early part of the following year. We understand that this was the SDT’s intent; however, the text is not clear that it allows for such deferments. We recommend modifying the requirement to read, “Be flexible to adjust to changing conditions and to findings from Vegetation Inspections. Adjustments to the plan including work deferments into a subsequence

Organization	Yes or No	Question 1 Comment
		year's work plan are permissible." E. R1.4 states that a process or procedure for response to an imminent threat of vegetation-related sustained outage is required. The MRO NSRS believes that the term "imminent threat" should be a NERC defined term. F. (R1) Since neither "operating range" nor "rated conditions" are defined NERC terms, this requirement R1 could be open to broad interpretation. As a result, the MRO NSRS recommends that the SDT consider alternatives that will reduce potential ambiguity. FAC-003 currently requires Clearance 2 to be maintained for 'all rated electrical operating conditions.' This suggests that vegetation clearances should be set in a manner such that required clearances will be maintained for conditions that include line loadings at both Normal and Emergency Ratings. The MRO NSRS recommends that the SDT consider additional specificity. Or, we recommend these two terms ("operating range" and "rated conditions") be defined by the SDT.
Consolidated Edison Company of New York Inc.	Disagree	Although CECONY agrees that each TO should be required to have a documented TVMP, we recommend changing the wording in Sections 1.2 and 1.3.2.In Section 1.2, CECONY recommends the wording to read, 'Specify a Vegetation Inspection of at least once per calendar year.' The additional wording regarding local and environmental factors may cause unnecessary confusion for some. In Section 1.3.2, the phrase '...and methods to be used...' should be changed to read, '...and methods that may be used....' to be consistent with the wording in Section 1.1. Also, the terms 'operating range' and 'rated conditions' in R1.6 should be clearly defined in the Standard and added to the NERC Glossary.
FirstEnergy Corp	Disagree	Although we mostly agree with Req. R1, we offer the following suggestions for improvement:Main Req. R1 - We suggest replacing the phrase "that describes how it conducts work" with "that describes vegetation control methods on its Active Transmission Line Right Of Way". We feel our proposed change more accurately describes the intent of the TVMP.Part 1.2 - We feel the phrase "local and environmental factors" is ambiguous and open to varying interpretations. We suggest R1.2 read "Specify a Vegetation Inspection frequency of at least once per calendar year." (Delete the remainder of the sentence).Part 1.3.3 - Regarding the second sentence "Adjustments to the plan within the year are permissible", we feel it would be clearer if it was changed to simply "Adjustments to the plan are permissible". There may be situations beyond the entity's control, where the work plan is not entirely implemented "within the year". These situations would justify the work being postponed and completed in the early part of the following year. FE believes this change maintains the intent of the drafting team based on the reference White Paper that permits deferral of work for various reasons. Part 1.6 - FE believes that this sub-part of R1 is redundant and and suggests it be removed. The primary R1 requirement text already references the need to consider all possible conductor locations and the effects of swag and sway. Additionally, sub-parts 1.1 - 1.5 will achieve the outcome which 1.6 is seeking. Parts 1.1 - 1.5 identify the strategies used to ensure that Table 1 clearances are not violated, which is accomplished through specifying vegetation control methods, requiring an annual inspection, adjusting the work plan to incorporate the inspection findings, allowing time for permitting and scheduling, having an imminent threat procedure and requiring an interim corrective action process. Requiring the Transmission

Organization	Yes or No	Question 1 Comment
		Owner to meet 1.6 by either identifying vegetation to conductor clearance in addition to Table 1, removing all trees on the active ROW, or managing vegetation at a maximum height, as the SDT has suggested, adds specificity that is burdensome and may lead to greater potential for a Transmission Owner to violate its own TVMP, in addition to the requirements already in place. If the SDT wants to merely assure that the TVMP adheres to the clearances specified in Table 1, then we suggest removing Part 1.6, and adding the following wording after "documented transmission vegetation management program" in the body of the text of main Requirement R1: "that adheres to the minimum vegetation clearance distances specified in Table 1 of Attachment 1".
Northern Indiana Public Service Company	Disagree	As written, the definition of "Active Transmission Right of Way" leaves it up to each T.O. to determine what is "active" and what is "inactive" R.O.W. The dimensions or physical description of these areas for any given R.O.W. are not required to be defined or documented by the T.O. in the TVMP or anywhere else for that matter. This creates the possibility for a T.O. to avoid violations of this standard or to inappropriately reduce maintenance activities by simply declaring that any offending vegetation resides in an inactive area. For Example: The T.O. typically maintains a R/W clear of trees 75 ft. to the side of the conductor. However, over a period of time, the T.O. allows trees to encroach in from the sides in several spans so that there is only 50 ft. of side clearance. A tree 60 ft. to the side in this narrowed area falls into the conductors but the T.O. declares the tree to have fallen from an inactive R.O.W. area since it wasn't actively being maintained. This is a major loophole that needs to be addressed. Am in agreement with R1.1 through R1.4. Disagree with the inclusion in R1.5 of the term "temporarily" when there are constraints on completing vegetation maintenance work. It is unimportant whether or not a constraint is temporary or permanent. What is important is that work cannot be completed as planned. When this happens, the T.O. needs to use a corrective process or implement mitigation measures in response to the constraint. The Technical Reference provides examples of permanent constraints such as "the discovery of easement stipulations which limit the T.O.'s rights" along with temporary constraints. This acknowledges the fact that any constraint, regardless of duration, should be addressed through a corrective action process or mitigation plan.
Oncor Electric Delivery	Disagree	Comments: Part 1.3.3. allows adjustments to the plan within the year but does not allow work to be deferred until the next year. This deferral of work impacts 1.3.1, 1.3.2 (possibly 1.3.4) but does not impact the reliability of the line. “Following the Annual Plan” should accommodate a TO responding to changing conditions (to include permitting and scheduling) and should not necessarily place a TO out of compliance. Are adjustments made outside of the plan year considered to be “missing” in Part 1.3.3 by definition of High VSL for R1?Part 1.3.4 states a TO should consider permitting and scheduling requirements in developing their annual plan. What if a TO took into consideration these requirements and the timing of these issues took longer than anticipated? These types of variables may result in the deferral of some line work until the next year. Requirement 1.3 should clarify what the compliance status of a TO if plan specified line work was not implemented that year due to permitting and scheduling issues?Consider: Adjustments to the plan within

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		the year are permissible. This could be inserted at 1.3 to cover all parts or just 1.3.3 and 1.3.4. In its current state, only 1.3.3 (Changes to conditions and Findings from Vegetation Inspections) is addressed.
Vegetation Management Team	Disagree	Comments: Disagree with R1.2 - Inspection Frequency. Very prescriptive. Please consider allowing TO's to select the frequency that best fits their requirements. BGE currently defines their inspection frequency as annually during the non-growing season, October 1 to May 1. Under the proposed language scheduling would be very challenging. Disagree with 1.3.3 which states that the annual work plan shall "Be flexible to adjust to changing conditions and to findings from vegetation inspections. Adjustment to the plan within the year are permissible."This wording would not allow a situation where the work plan is not entirely implemented "within the year". There may be times where one may be justified to postpone work that is planned for the end of the year to be moved to the first part of the following year. We suggest removing the words "within the year" from R.1.3.3Disagree with R1.6 and M1.6 The purpose of the TVMP is to prevent vegetation related outages and improve the reliability of the electric system. The imminent threat provision allows for a procedure to address imminent threats before they become violations. (R1.4). Therefore, as long as the TO follows the imminent threat procedure, then a violation will not result. A violation will result only if the TO does not have an imminent threat procedure or fails to implement that procedure. Merely having an imminent threat is not a violation. By comparison, the new draft states any observed encroachments are reportable violations because the requirements do not permit a procedure to address encroachments. (See R1.6, R3. R4). The better approach would be to require the remediation of encroachments according to a TVMP but not make every found encroachment a violation. An encroachment is not necessarily "likely to cause a Sustained Outage at any moment," the level of severity required to be an imminent threat. (p.20). It is logical to conclude that imminent threats are more severe than encroachments. In fact, the technical report states that an encroachment due to operation of a transmission line beyond its recognized rating is beyond the scope of R4, the requirement for prevention of encroachments. (p.31). If this is the case, just like the process by which the TO is given the opportunity to address imminent threats, encroachments should also be addressed via a pre-determined process before becoming a violation of the standard. Further the requirement as drafted is a disincentive to deploy more sophisticated tools to identify threats to its system, such as software-enabled LiDAR Therefore, we suggest the following changes to the requirements: R1.6: require a process or procedure for response when any [REMOVE: specify the maintenance strategies used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that] Table 1 clearances in FAC-003-2-Attachment 1 are never violated are encroached upon.M1.6: The Transmission Owner's transmission vegetation management program documentation specifies [REMOVE: the maintenance strategies used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that] an encroachment process or procedure for responding if any Table 1 clearances in FAC-003-2-Attachment 1 [REMOVE: are never violated] are encroached upon. The maintenance strategies consider the sag and sway of the conductor throughout its operating range under rated conditions.

Organization	Yes or No	Question 1 Comment
Hydro-Quebec TransEnergie (HQT)	Disagree	Each TO should be required to have a documented TVMP. Recommend changing the wording in Sections 1.2 and 1.3.2.In Section 1.2, recommend changing the wording to read, ‘Specify a Vegetation Inspection frequency.’ The minimum frequecy should be left to the TO according to its system and environment characteristics. also, the additional wording regarding local and environmental factors may cause unnecessary confusion for some. In Section 1.3.2, the phrase ‘...and methods to be used...’ should be changed to read, ‘...and methods that may be used....’ to be consistent with the wording in Section 1.1. Also, the terms ‘operating range’ and ‘rated conditions’ in R1.6 should be clearly defined in the Standard and added to the NERC Glossary to avoid confusion. There is an inconsistency between R1.2 and R3. R1.2 requires the TO to carry out inspections at least once per calendar year. R3 requires the TO to carry out inspections per the frequency defined in its vegetation management program. It is preferred that the TO be allowed to specify the frequency and timing as stated in R3. Once per calendar year is not sensitive to local and environmental factors. For example, facilities in the Northeast are located in an environment where there is a long (7-8 month) dormant period -vegetation does not grow. Specify a frequency of one inspection per dormant period. This inspection could take place between September and April annually. In one dormant period we might inspect in November and inspect again 14 months later in January. We would meet the inspection need per R3, but fail to have inspected in a calendar year, thus violating R1.2. Other TO’s may be located in parts of the country with little or no vegetation and not need a once per calendar year inspection. Thus, R1.2 should allow the TO to specify an inspection program that is sensitive to local and environmental factors, not the calendar.
Independent Electricity System Operator	Disagree	Each TO should be required to have a documented TVMP. Recommend changing the wording in Sections 1.2 and 1.3.2.In Section 1.3.2, the phrase ‘...and methods to be used...’ should be changed to read, ‘...and methods that may be used....’ to be consistent with the wording in Section 1.1. Also, the terms ‘operating range’ and ‘rated conditions’ in R1.6 should be clearly defined in the Standard and added to the NERC Glossary to avoid confusion. There is an inconsistency between R1.2 and R3. R1.2 requires the TO to carry out inspections at least once per calendar year. R3 requires the TO to carry out inspections per the frequency defined in its vegetation management program. It is preferred that the TO be allowed to specify the frequency and timing as stated in R3. Once per calendar year is not sensitive to local and environmental factors. For example, facilities in the Northeast are located in an environment where there is a long (7-8 month) dormant period -vegetation does not grow. Specify a frequency of one inspection per dormant period. This inspection could take place between September and April annually. In one dormant period we might inspect in November and inspect again 14 months later in January. We would meet the inspection need per R3, but fail to have inspected in a calendar year, thus violating R1.2. Other TO’s may be located in parts of the country with little or no vegetation and not need a once per calendar year inspection. Thus, R1.2 should allow the TO to specify an inspection program that is sensitive to local and environmental factors, not the calendar.If the above suggestion is not accepted, recommend changing the wording in Section 1.2 to read,

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		'Specify a Vegetation Inspection of at least once per calendar year.' Also, the additional wording regarding local and environmental factors may cause unnecessary confusion for some.
ISO New England Inc.	Disagree	Each TO should be required to have a documented TVMP. Recommend changing the wording in Sections 1.2 and 1.3.2.In Section 1.2, recommend changing the wording to read, 'Specify a Vegetation Inspection of at least once per calendar year.' The additional wording regarding local and environmental factors may cause unnecessary confusion for some. In Section 1.3.2, the phrase '...and methods to be used...' should be changed to read, '...and methods that may be used....' to be consistent with the wording in Section 1.1. Also, the terms 'operating range' and 'rated conditions' in R1.6 should be clearly defined in the Standard and added to the NERC Glossary to avoid confusion. There is an inconsistency between R1.2 and R3. R1.2 requires the TO to carry out inspections at least once per calendar year. R3 requires the TO to carry out inspections per the frequency defined in its vegetation management program. It is preferred that the TO be allowed to specify the frequency and timing as stated in R3. Once per calendar year is not sensitive to local and environmental factors. For example, facilities in the Northeast are located in an environment where there is a long (7-8 month) dormant period -vegetation does not grow. Specify a frequency of one inspection per dormant period. This inspection could take place between September and April annually. In one dormant period we might inspect in November and inspect again 14 months later in January. We would meet the inspection need per R3, but fail to have inspected in a calendar year, thus violating R1.2. Other TO's may be located in parts of the country with little or no vegetation and not need a once per calendar year inspection. Thus, R1.2 should allow the TO to specify an inspection program that is sensitive to local and environmental factors, not the calendar.
Northeast Power Coordinating Council--RSC	Disagree	Each TO should be required to have a documented TVMP. Recommend changing the wording in Sections 1.2 and 1.3.2.In Section 1.2, recommend changing the wording to read, 'Specify a Vegetation Inspection of at least once per calendar year.' The additional wording regarding local and environmental factors may cause unnecessary confusion for some. In Section 1.3.2, the phrase '...and methods to be used...' should be changed to read, '...and methods that may be used....' to be consistent with the wording in Section 1.1. Also, the terms 'operating range' and 'rated conditions' in R1.6 should be clearly defined in the Standard and added to the NERC Glossary to avoid confusion. There is an inconsistency between R1.2 and R3. R1.2 requires the TO to carry out inspections at least once per calendar year. R3 requires the TO to carry out inspections per the frequency defined in its vegetation management program. It is preferred that the TO be allowed to specify the frequency and timing as stated in R3. Once per calendar year is not sensitive to local and environmental factors. For example, facilities in the Northeast are located in an environment where there is a long (7-8 month) dormant period -vegetation does not grow. Specify a frequency of one inspection per dormant period. This inspection could take place between September and April annually. In one dormant period we might inspect in November and inspect again 14 months later in January. We would meet the inspection need per R3, but fail to have inspected in a calendar year, thus violating R1.2. Other TO's may be

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		located in parts of the country with little or no vegetation and not need a once per calendar year inspection. Thus, R1.2 should allow the TO to specify an inspection program that is sensitive to local and environmental factors, not the calendar.
American Transmission Company	Disagree	FERC Order No. 693 does not direct NERC to establish minimum inspection cycles. Rather, FERC stated a goal for the Standard to '...assure that transmission owners conduct inspections at reasonable intervals.' (Order 693, P. 720)ATC recommends that that the SDT drop the "once per year" language from the requirement and replace it with the following language:"Document a Vegetation Inspection frequency that considers local and environmental factors." ATC believes that this language is in alignment with Commission's Order 693 and responsive to maintaining system reliability.The current language a) limits the ability of an entity to set a longer inspection cycle if its local / environmental and b) requires entities to justify the once per year cycle. ATC believes that the SDT needs to address this concern by making modifications to the requirement in order to prevent entities from allocate funds on efforts that do not benefit the BPS. R 1.3.3 states that the annual work plan shall...."Be flexible to adjust to changing conditions and to findings from Vegetation Inspections. Adjustments to the plan within the year are permissible."ATC is concerned that the wording would not allow a situation where the work plan is not entirely implemented "within the year". There may be instances where you may be justified to postpone the work planned at the end of the year and must be moved into early part of the following year. ATC recommends removing the words "within the year "in R1.3.3.R 1.4 states that a process or procedure for response to an imminent threat of vegetation-related sustained outage is required. ATC believes that the term "imminent threat" should be a NERC defined term. An alternate option is to include the following language "imminent threat as defined by the entity". This makes it clear that the entity is allowed to define the term. ATC recommends that the SDT consider an alternative structure for the wording of R 1.6, where the current wording states '...specify...maintenance strategies ... to ensure that Table 1 clearances are never violated.'To improve clarity and better reflect the intent for this requirement as stated in the Technical Paper, ATC suggests consideration of the language directly from the Technical Paper (p. 24). Thus, the requirement could be edited to state: "Maintenance strategies must be designed to a) meet the Table 1 clearances in Attachment 1 and b) consider all possible locations of the conductor for rated design conditions."R 1.6 states that maintenance strategies in companies' vegetation management programs must consider 'sag and sway of the conductor throughout its operating range under rated conditions.' Since neither 'operating range' nor 'rated conditions' are defined NERC terms, this requirement could be open to broad interpretation. As a result, ATC recommends that the SDT consider alternatives that will reduce potential ambiguity. FAC-003 currently requires Clearance 2 to be maintained for 'all rated electrical operating conditions.' This suggests that vegetation clearances should be set in a manner such that required clearances will be maintained for conditions that include line loadings at both Normal and Emergency Ratings. ATC recommends that the SDT consider additional specificity.

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JEA	Disagree	Please review the work being done by the ad hoc committee headed by Gerry Cauley that is attempting to guide standard development towards results or performance based requirements. It seems that vegetation management can be handled by this approach and that the paperwork requirement for a documented policy produces a heavy paperwork burden without requisite benefit to reliability added. However, the requirement for a documented procedure for "Imminent Threats" is appropriate as this is in essense an emergency response planning requirement. The requirement for an annual work plan is also appropriate as it is a requirement to demonstrate that appropriate planning is being done to meet the objectives of this standard.
Public Service Co. of New Mexico	Disagree	PNM prefers the Clearance 1/Clearance 2 setup. PNM does not like the MVCD classification as it implies - to the general public - that the MVCD is the only clearance needed. The distances are extremely small. We as a utility company realize this is only the "minimum" distance however it will not be interpreted that way by others outside our industry. Either go back to the Clearance 1 & 2 designation or change the MVCD name to illustrate the criticality of these clearances. Suggestions: Critical Vegetation Clearance Distance or Imminent Threat Vegetation Clearance Distance.Secondly, PNM believes there needs to be some sort of minimum qualifications for those individuals responsible for development and implementation of TVMP.
Manitoba Hydro	Disagree	R 1.2 states that the TVMP shall “Specify a Vegetation Inspection frequency of at least once per calendar year that takes into account local3 and environmental factors.”R 1.2 should read: “Specify a Vegetation Inspection frequency of at least once per calendar year.” (and remove the balance of the sentence)R 1.3.3 states that the annual work plan shall....”Be flexible to adjust to changing conditions and to findings from Vegetation Inspections. Adjustments to the plan within the year are permissible.”The wording would not allow a situation where the work plan is not entirely implemented “within the year”. There may be instances where you may be justified to postpone the work planned at the end of the year and must be moved into the following year, or an alternative strategy assigned, pushing the work even further out. Remove the words “within the year “in R1.3.3.R 1.4 states that a process or procedure for response to an imminent threat of vegetation-related sustained outage is required. The term “imminent threat” should be a NERC defined term. The SDT should consider an alternative structure for the wording of R 1.6, where the current wording states ‘...specify...maintenance strategies ... to ensure that Table 1 clearances are never violated.’To improve clarity and better reflect the intent for this requirement as stated in the Technical Paper, consider the language directly from the Technical Paper (p. 24). Thus, the requirement could be edited to state: “Maintenance strategies must be designed to a) meet the Table 1 clearances in Attachment 1 and b) consider all possible locations of the conductor for rated design conditions.”R 1.6 states that maintenance strategies in companies’ vegetation management programs must consider ‘sag and sway of the conductor throughout its operating range under rated conditions.’ Since neither ‘operating range’ nor ‘rated conditions’ are defined NERC terms, this requirement could be open to broad interpretation. As a result, the SDT should consider alternatives that will reduce potential ambiguity. FAC-003 currently requires Clearance 2 to be maintained for ‘all rated

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		electrical operating conditions.' This suggests that vegetation clearances should be set in a manner such that required clearances will be maintained for conditions that include line loadings at both Normal and Emergency Ratings. The SDT should consider additional specificity.
Progress Energy Carolinas, Inc.	Disagree	R 1.3.3 states that the annual work plan shall....”Be flexible to adjust to changing conditions and to findings from Vegetation Inspections. Adjustments to the plan within the year are permissible.”The wording as proposed would not allow situations where the “work plan” is not entirely implemented “within the year”, which conflicts with the requirement to be flexible and adjust to changing conditions. To eliminate this conflict between requirements, PEC recommends removing the words “within the year “in R1.3.3.
Lee County Electric Cooperative	Disagree	R1 1.5 - define 'temporarily'. Alternative: Define a maximum period of time. ex: beyond one inspection cycle, or based on environmental conditions, one growth cycle; or based on when access was restricted - when the last or next inspection occurred or is scheduled to occur.
CenterPoint Energy	Disagree	R1 refers to “Active Transmission Line Rights of Way” which are not defined as to their limits within the Standard. The SDT has indicated in its response to 1st Draft Comments from CenterPoint Energy that the “...Transmission Owner is responsible for defining the Active Transmission Line Right of Way.” However, that determination clause is not included in the current definition. CenterPoint Energy recommends deleting the phrase “on its Active Transmission Line Rights of Way” from R1. The phrase, “...considering all possible locations the conductor may occupy under the effects of sag and sway throughout is operating range and under rated conditions” , by itself defines the airspace that must be maintained. R1.6 adds the MVCD distance requirement to the sag and sway geometry further defining the airspace that must be maintained. R1 requires no specific definition of a right of way.As written, R1 does not address how a utility conducts its work to address the fall-in of trees into an adjacent transmission line. The determination of the limits of the right of way are only necessary in the Standard for determining the reporting exceptions for certain Sustained Outages in R8 (fall-in) as evidenced in measure M8 through self-certification reports.The Standard and the Technical Reference provide no specific justification for defining a 1-year inspection frequency in R1.2. The requirement itself does not take into account “local and environmental factors”, which may indicate a longer inspection frequency is warranted. The Technical Reference states that the inspection frequency is required to be “at least once per calendar year”. The SDT’s only justification for this determination is found in its response to 1st Draft Comments, “...the consensus of the SDT is that inspection of any operating transmission line should be done annually... “. This statement alone is not compelling. No further supporting arguments have been provided. CenterPoint Energy believes that this minimum inspection frequency is arbitrary and is not necessary or appropriate for all registered entities. Registered entities are in the best position to determine appropriate inspection frequencies that take into account local and environmental factors found in their service territories. CenterPoint Energy strongly recommends that R1.2 be revised to allow the registered entity to determine the appropriate inspection frequency for their service territory. The

Organization	Yes or No	Question 1 Comment
		revised R1.2 would read "Specify a Vegetation Inspection frequency that takes into account local and environmental factors to prevent Sustained Outages."
Platte River Power Authority Vegetation Management Group	Disagree	R1. currently says "...under rated conditions". It should say "...under Rated Electrical Operating Conditions" a NERC defined term. Defined as: The specified or reasonably anticipated conditions under which the electrical system or an individual electrical circuit is intend/designed to operate.Although we appreciate the SDT's need to address a minimum vegetation inspection frequency as ordered by FERC directive 693, we believe that system conditions vary too widely from utility to utility and even within utilities to specify a Vegetation Inspection (VI) frequency of at least once per calendar year in R1.2. We think the SDT should consider making the minimum VI broader to cover different vegetation types and local factors. R1.3. Should be consistent in wording with R1.1. and R1.2. as follows: 1.3. Specify an annual work plan that shall:We agree with the SDT to remove the 'fill in the blank' requirement for personnel requirements in FAC-003-1.R1.3.2. "Identify the work to be performed and methods to be used", is redundant as it is address in other requirement in the standard. The work to be performed is included under R1. "...that describes how it conducts work" and the methods to be used is included under R1.1. Specify the methods that the TO may use to control vegetation. R1.3.3. Should read: Be flexible to adjust to changing conditions of the vegetation on the Active Transmission Line ROW, emergencies, and other significant changing conditions found during Vegetation Inspections. Adjustments to the plan within the year are permissible but must always ensure the reliability of the electric transmission system.R1.4. Should be consistent in wording with R1.1. and R1.2. as follows:1.4. Specify a process or procedure...We believe that mitigation measures in R1.4 of FAC-003-1 are better than the new corrective action process in R1.5 of FAC-003-2. However, if it is decided to keep R1.5. the SDT should remove the words "interim" and "temporarily" as they do not provide clarity. Some constraints are permanent or long-term and it would be appropriate to have a corrective action process to address all constraints. R1.6. currently says, "... under rated conditions". It should say, "... under Rated Electrical Operating Conditions" a NERC defined term. We have some concern that the general public will misinterpret the Table 1 clearances in Attachment 1 and expect constant maintenance in order to allow their vegetation to be as close to line as possible at all times. The addition of a critical clearance distance to be achieved at the time of work, similar to the Clearance 1 in FAC-003-1 may explain why you need more clearance distance.
Transmission Owner	Disagree	R1., 1.3.,1.3.2. Should read: Identify the work to be performed. The method does not contribute to reliability and places an un-needed burden on auditor and Transmission Owner. R1., 1.4. The term Imminent Threat is vague. FPL recommends that the Transmission Owner should be directed to define it based on its construction and local environmental conditions.
Salt River Project	Disagree	R1.3: In "Require an annual work plan" recommend changing the word "require" to "define". R1.5: This appears to replace the old R1.4. Suggest changing back to how it was worded in R1.4, a better description.

Organization	Yes or No	Question 1 Comment
		As there was a need to replace "mitigation" and alternative would be to place with "corrective action".
Puget Sound Energy	Disagree	Requirement 1.6, while a good theory statement, does not have the impact of Clearance 1 in the existing standard. When agencies and reluctant landowners look at this standard, they will not see this requirement the same way Clearance 1 is seen. Requirement 1.6 will be seen as a procedural, not a justification for utilizing utility best management practices for vegetation management. R1.6 indicates that the maintenance strategy used must be specified and then identifies "minimum vegetation to conductor distance" as an example strategy. The minimum vegetation to conductor distance as table 1 is titled is the goal of the strategy, but not a strategy. This creates confusion regarding the intention of this requirement. Modify R1.6 to read "Ensure Table 1 Attachment 1 clearances are never violated considering sag and sway of the conductor throughout its operating range under rated conditions and local vegetation characteristics and factors under non-storm weather variances." Because the distances in Table 1 are so small, it could appear to a non-familiar customer or local agency that the standard is becoming less stringent raising even more opportunity for customer resistance and the need to create more unique interim corrective actions to manage. The inability of an entity to follow a consistent plan raises the risk of non-compliance.
Central Maine Power an Energy East Company	Disagree	Suggest that NERC define operating range and rated conditions.
Nebraska Public Power District	Disagree	The requirement in R1.2 should allow the Transmission Owner to set the frequency of inspection. The T.O. should be able to determine what frequency based on their system. We also agree with Xcel on an exemption if new technology such as LIDAR is used. This will allow the T.O. to determine objectively what vegetation needs to be addressed and when.R1.4: "imminent threat" needs to be defined.R1.5: delete "temporarily" from the requirement. This is a difficult word to define and provide guidance on.R1.6 should be reworded using language from the Technical Paper (p. 24). "Maintenance strategies must be designed to (a) meet the table 1 clearances in attachment 1, and (b) consider all possible locations of the conductor for rated design conditions."
Utility Arborist Association	Disagree	The Utility Arborist Association (UAA) considers it imperative to include a requirement for transmission operators to adopt the science-based, industry accepted practices in ANSI A300. ANSI A300 was designed to ensure appropriate and effective practices are implemented, while allowing each utility the flexibility to develop a program that considers site specific factors. The UAA recognizes that there are varying levels of technical competency within the industry among individual utility vegetation management (UVM) programs. While the majority of utilities currently apply A300 routinely, there are still those that do not. We believe that utilities that have failed to implement A300 could potentially become involved in future incidents due to insufficient understanding of effective utility vegetation management practices. The UAA thinks that FAC-003-02 should ensure that all utilities have successful programs to mitigate tree and power line conflicts,

Organization	Yes or No	Question 1 Comment
		regardless of their size, budgets and other available resources. A specific requirement to adherence to A300 will ensure that compliance with FAC-003-02 across North America will be uniform and effective. Without this requirement, we fear that utilities with less robust resources and knowledge may become the weakest link in the electrical system. As such, the UAA strongly encourages the direct reference to A300 within the standard rather than as a footnote.
E.ON U.S.	Disagree	This will add significant cost to vegetation management budgets. The MVCD concept will require the use of LIDAR and will add approximately $250k per year to utility company expenses. These costs include equipment, training, LIDAR survey and personnel costs.
Arizona Public Service	Disagree	Utilities should be held to following ANSI A-300 standards and BMP's for best management practices. By following these standards there wouldn't be a need for the FAC-003 standard. There should not be a footnote but a requirement. Personnel qualifications should be a requirement. There are certification programs through the International Society of Arboriculture that certify a minimum level of competence to manage a vegetation management program. This also requires ongoing training and education to keep up with the latest technologies on UVM. NERC and FERC still need to be aware that federal land agencies are making decisions without any education or knowledge on UVM activities which affect transmission reliability. There needs to be a clearance 1 requirement in the standard. If utilities are required to follow this standard it gives them leverage with dealing with these federal land agencies.
Idaho Power Company	Disagree	We agree with letting the Transmission Owner decide on methods to control vegetation management. We believe personnel qualifications should be included but as determined by the Transmission Owner. We agree that annual inspections should be required. However, we would prefer R1.3 to read as "Specify an annual work plan..." rather than "Require an annual work plan..." to be consistent with the other subsections of the R1 requirements. We believe R1 should allow flexibility to integrate technology, in particular Lidar, as an acceptable patrol.
Ameren	Disagree	Would suggest the term "normal" in front of "sag and sway throughout its operating range"...or " design of" to address the exceptions for environmental conditions.
ISO/RTO Council		The SRC has no comment on this question.

2. As stated in the background information above, in response to industry comments, the Requirement for implementation of Imminent Threat process/procedure (the new R2) is revised. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Organization	Yes or No	Question 2 Comment
Entegra Power Group LLC		No comment
Ameren	Agree	
American Electric Power	Agree	
Associated Electric Cooperative, Inc.	Agree	
Bonneville Power Administration	Agree	
CenterPoint Energy	Agree	
Central Maine Power an Energy East Company	Agree	
Consolidated Edison Company of New York Inc.	Agree	
Duke Energy	Agree	
Entergy Services, Inc	Agree	
Georgia Transmission Corporation	Agree	
Hydro One Networks inc.	Agree	

Organization	Yes or No	Question 2 Comment
Hydro-Quebec TransEnergie (HQT)	Agree	
Idaho Power Company	Agree	
Independent Electricity System Operator	Agree	
ISO New England Inc.	Agree	
JEA	Agree	
Manitoba Hydro	Agree	
National Grid	Agree	
Nebraska Public Power District	Agree	
New Brunswick Power Transmission	Agree	
North Carolina Electric Membership Corporation	Agree	
Northeast Power Coordinating Council--RSC	Agree	
Northeast Utilities	Agree	
Northern Indiana Public Service Company	Agree	
Oncor Electric Delivery	Agree	

Organization	Yes or No	Question 2 Comment
Orange and Rockland Utilities, Inc.	Agree	
Pacific Gas and Electric Co.	Agree	
Platte River Power Authority Vegetation Management Group	Agree	
Progress Energy Carolinas, Inc.	Agree	
Public Service Co. of New Mexico	Agree	
Puget Sound Energy	Agree	
ReliabilityFirst Corporation	Agree	
SCE&G	Agree	
SERC Vegetation Managment Sub-committee (VMS)	Agree	
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tampa Electric Company	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Transmission Owner	Agree	

Organization	Yes or No	Question 2 Comment
Tucson Electric Power Company	Agree	
TVA	Agree	
TVA	Agree	
TVA	Agree	
US Bureau of Reclamation	Agree	
Vegetation Management Team	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Xcel Energy	Agree	
Pepco Holdings, Inc - Affiliates (PHI)	Agree	PHI agrees with the requirement but notes that Operating Process is a NERC defined term. The SDT should review the definition and use capitalization for Glossary terms.
NERC Standards Review Subcommittee	Agree	Prefer the distances specified in the current IEEE Standard as opposed to the Gallet equation.
Southern California Edison Company	Agree	SCE generally agrees with the language of the requirement and the assignments. However, it is unclear why the Violation Risk Factor is rated as "Medium," rather than "Lower."
FirstEnergy Corp	Disagree	Although we mostly agree with Req. R2, we offer the following suggestion for improvement. The phrase "actual knowledge" is ambiguous and could be difficult to measure. For instance, if the responsible entity receives a voice mail or email regarding an imminent threat, then that would technically mean he has actual knowledge of the alleged threat; however, only after the entity reviews and confirms the alleged situation can it be judged a true imminent threat. Therefore, we suggest a change from "actual knowledge" to

Organization	Yes or No	Question 2 Comment
		"confirmation".
E.ON U.S.	Disagree	E.ON U.S. believes that requirement to prove “no incident occurred” for an audit would be impossible to accomplishE.ONU.S. believes that the SDT should clarify what is meant by “normal Operating Practices,” specifically identifying what practices are necessary to ensure compliance with the standard.E.ON U.S. believes that the proposed standard is in conflict with TOP-1 (the imminent threat procedure could require an operator to take a line out of service thereby putting the grid at risk).
PacifiCorp	Disagree	PacifiCorp thinks it is very important for improved reliability to directly reference ANSI A300, rather than relegate it to a footnote. ANSI A300 is science-based, and proven to be effective. Directly referencing adherence to A300 will encourage uniform compliance with FAC-003 across North America. Without this reference, PacifiCorp fears grid stability could be threatened by ineffective practices applied by utilities that lack sufficient expertise to manage their systems. PacifiCorp believes that those utilities could create future blackouts due simply to a lack of understanding about proper utility vegetation management practices. Consequently, PacifiCorp urges direct reference to A300 within the standard. PacifiCorp believes eliminating clearance 1 will be detrimental to reliability. Clearance 1 is important for utilities to account for the dynamics of conductor movement and vegetative growth. This required analysis should lead to development of a more informed vegetation management program. Clearance 1 also gives utilities leverage with landowners, governmental agencies and local regulators to achieve the necessary operational clearances. If the only required clearance is the R4 Minimum Vegetation Clearance Distance, landowners and local regulators will push the utility to maintain a little more than those clearances rather than properly taking tree growth into account.
Arizona Public Service	Disagree	The SDT needs to come up with a standardized format for the imminent threat process. All utilities need to be audited the same way. This requirement is too vague since it has a VSL of severe. In the beginning of this document it states the requirement will be clearer and in an unambiguous manner. Here each utility can make up their process and will be audited differently.
BC Transmission Corporation	Disagree	The STD needs to specify a standardized format for the imminent threat process, this will allow for consistency in the audit process which is important because the VSL is severe. If each utility specifies their own process it will be up to the subjectivity of the auditors who often do not have a vegetation management background to determine if the process is adequate.
Lee County Electric Cooperative	Disagree	This requirement seems redundant to R1. 1.4 The process or procedure required in R1. 1.4 includes implementing the procedure. Steps taken to mitigate the threat would be documented and could be considered as implementing the process/procedure. Alternative: either eliminate the new R2 or edit R. 1.4 to

Organization	Yes or No	Question 2 Comment
		include evidence.
ISO/RTO Council		The SRC has no comment on this question.

3. As stated in the background information above, in response to industry comments, the Requirement for conducting Vegetation Inspections (the new R3) is revised. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Organization	Yes or No	Question 3 Comment
Entegra Power Group LLC		No comment
Ameren	Agree	
American Electric Power	Agree	
Associated Electric Cooperative, Inc.	Agree	
Bonneville Power Administration	Agree	
Consolidated Edison Company of New York Inc.	Agree	
Duke Energy	Agree	
E.ON U.S.	Agree	
Entergy Services, Inc	Agree	
Georgia Transmission Corporation	Agree	
Lee County Electric Cooperative	Agree	
Manitoba Hydro	Agree	

Organization	Yes or No	Question 3 Comment
Nebraska Public Power District	Agree	
New Brunswick Power Transmission	Agree	
North Carolina Electric Membership Corporation	Agree	
Northeast Utilities	Agree	
Oncor Electric Delivery	Agree	
Pacific Gas and Electric Co.	Agree	
PacifiCorp	Agree	
Progress Energy Carolinas, Inc.	Agree	
Public Service Co. of New Mexico	Agree	
Puget Sound Energy	Agree	
SCE&G	Agree	
SERC Vegetation Managment Sub-committee (VMS)	Agree	
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tampa Electric Company	Agree	

Organization	Yes or No	Question 3 Comment
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Transmission Owner	Agree	
Tucson Electric Power Company	Agree	
TVA	Agree	
TVA	Agree	
TVA	Agree	
US Bureau of Reclamation	Agree	
Vegetation Management Team	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
ReliabilityFirst Corporation	Agree	Do we need the parenthetical statement “as measured in line miles”?
Central Maine Power an Energy East Company	Agree	Inspection frequency should be designed to meet the objective of this standard.
MRO NERC Standards Review Subcommittee	Agree	MRO NSRS suggests that the referenced footnote 5 be modified to include “species epidemics,” such as bark beetles; this footnote 5 should be referenced. Additionally, footnote 5 could be modified to include “species epidemics” between “logging” and “animal severing tree.” R3 states that “Each Transmission Owner shall conduct Vegetation Inspections of all applicable lines (as measured in line miles) in accordance with the frequency specified in its transmission vegetation management program, the MRO NSRS recommends that the phrase “of all applicable lines (as measured in line miles)” be removed from R3. This is understood by

Organization	Yes or No	Question 3 Comment
		Applicability section A4.2.
American Transmission Company	Agree	R 3 states that “Each Transmission Owner shall conduct Vegetation Inspections of all applicable lines (as measured in line miles) in accordance with the frequency specified in its transmission vegetation management program,ATC recommends that the phrase “of all applicable lines (as measured in line miles)” be removed from R 3. This is understood by Applicability section A 4.2.
Southern California Edison Company	Agree	SCE generally agrees with the language of the requirement, but would suggest the following revision to Footnote 4 in order to clarify the text:Examples include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, ice storms, floods, and major storms as defined either by the Transmission Owner or an applicable regulatory body.
Hydro One Networks inc.	Disagree	(a) As compared with the current version, the proposed draft is still excessively prescriptive. Depending on local conditions, an annual inspection may not be necessary. The TO should have the ability to decide on the frequency of the inspections as long as the reliability of the BES is not compromised. For example, vegetation growth in Northeastern North America has long (7-8 months) dormant periods. (b) There seems to be an inconsistency between R1.2 and R3. R1.2 requires the TO to carry out inspections at least once per calendar year. R3 requires the TOs to carry out inspections per the frequency defined in its TVMP. According to our comment in (a) above, the TO should have the prerogative of specifying the frequency and timing as stated in R3. Once per calendar year is not sensitive to local and environmental factors. For example, vegetation growth in North Eastern North America has a long (7-8 month) dormant period. The entity should be able to specify a frequency of one inspection per dormant period. This inspection could take place between September and April annually. In one dormant period there might be an inspection in November, and an inspection again 14 months later in January. Accordingly, R3 is more appropriate. Other TOs may be located in parts of the continent with little or no vegetation and not need a once per calendar year inspection. Thus, R1.2 should allow the TOs to specify an inspection program that is sensitive to local and environmental factors, not the calendar. (c) In addition, VRFs and VSLs are based on percent of “total line miles specified by its TVMP”; this statement should be qualified by including something like “total applicable line miles specified by its TVMP”, as there may be circuits included in a vegetation management program that are not subject to the FAC-003 standard (sub-200kv, non-IROL lines). This also better aligns with the text of R3 (“...shall conduct Vegetation Inspections of all applicable lines...”). Also, we would suggest explicitly stating line kilometers as an acceptable measure for those using the metric system.
Idaho Power Company	Disagree	Include in the exceptions ‘unless constrained by federal and environmental restrictions’ along with natural disasters. Federal agencies can and have prevented vegetation management measures due to environmental, biological, and/or cultural concerns. In footnote 4, insect infestation should be added as a form

Organization	Yes or No	Question 3 Comment
		of natural disaster. Also, recommend changing 'major storms' to 'major events' in this footnote.
National Grid	Disagree	National Grid sees inconsistency between R1.2 and R3. R1.2 requires the TO to carry out inspections at least once per calendar year. R3 requires the TO to carry out inspections per the frequency defined in its vegetation management program. National Grid prefers that the TO be allowed to specify the frequency and timing as stated in R3. Once per calendar year is not sensitive to local and environmental factors. For example, National Grid facilities in the northeast are located in an environment where there is a long (7-8 month) dormant period - vegetation does not grow. National Grid would specify a frequency of one inspection per dormant period. This inspection could take place between September and April annually. In one dormant period we might inspect in November and inspect again 14 months later in January. We would meet the inspection need per R3, but fail to have inspected in a calendar year, thus violating R1.2. Other TO's may be located in parts of the country with little or no vegetation and not need a once per calendar year inspection. Thus, R1.2 should allow the TO to specify an inspection program that is sensitive to local and environmental factors, not the calendar.
Pepco Holdings, Inc - Affiliates (PHI)	Disagree	PHI appreciates the change, however, the SDT has designated the Regional Entity to provide alternate time periods for inspections. This should be the PC or RC. The TO should submit a request for alternate periods to the designated entity.
Salt River Project	Disagree	R1.2 specifies that vegetation inspections are to be conducted at least once per calendar year, yet in R3 it states that the Transmission Owner shall conduct Vegetation Inspections of all applicable lines in accordance with the frequency specified in the transmission vegetation management program. Although SRP conducts its transmission inspections on an annual basis, the Transmission Owner should be allowed to define the inspection frequency based on the operations of their utility company as best defined in their individual TVMP. Whichever definition is approved it should be stated the same in both R1.2 and in R3.
Platte River Power Authority Vegetation Management Group	Disagree	R3 says, "each TO shall conduct Vegetation Inspections of all applicable lines in accordance with the frequency specified in its transmission vegetation management program". However, R1.2. says that the TO shall specify a Vegetation Inspection frequency of at least once per calendar year. The two requirements seem to be inconsistent. We assume that R3 was worded to accommodate a more frequent Vegetation Inspection but it isn't clear.
Hydro-Quebec TransEnergie (HQT)	Disagree	Refer to the response to Question 1.
Independent Electricity System	Disagree	Refer to the response to Question 1.

Organization	Yes or No	Question 3 Comment
Operator		
ISO New England Inc.	Disagree	Refer to the response to Question 1.
Northeast Power Coordinating Council--RSC	Disagree	Refer to the response to Question 1.
JEA	Disagree	The requirement should simply be that the entity will conduct a Vegetation Inspection at least once per calendar year (per the push for results/performance based requirements). The caveats for natural disasters seem reasonable.
CenterPoint Energy	Disagree	The term “line miles” is not a defined NERC term. The industry terms “structure miles” and “circuit miles” are more common. The NERC Transmission Availability Data System (TADS) utilizes a defined term of “circuit miles” which would be a better choice to avoid confusion and provide the same capability for determining a percent complete status. Transmission Owners are already required to report the number of “circuit miles” of their (greater than or equal to) 200kV transmission line assets annually to TADS.
BC Transmission Corporation	Disagree	The TO's should be required to inspect each line at least once a year. This is critical to eliminating outages and would provide a definite measure for the audit process. The phrase as measured in line miles adds confusion to the requirement. It should state that the applicable lines be inspected along the entire length.
Orange and Rockland Utilities, Inc.	Disagree	There is an inconsistency between R1.2 and R3. R1.2 requires the TO to carry out inspections at least once per calendar year. R3 requires the TO to carry out inspections per the frequency defined in its vegetation management program. It is preferred that the TO be allowed to specify the frequency and timing as stated in R3. Once per calendar year is not sensitive to local and environmental factors. For example, facilities in the Northeast are located in an environment where there is a long (7-8 month) dormant period -vegetation does not grow. Specify a frequency of one inspection per dormant period. This inspection could take place between September and April annually. In one dormant period we might inspect in November and inspect again 14 months later in January. We would meet the inspection need per R3, but fail to have inspected in a calendar year, thus violating R1.2. Other TO’s may be located in parts of the country with little or no vegetation and not need a once per calendar year inspection. Thus, R1.2 should allow the TO to specify an inspection program that is sensitive to local and environmental factors, not the calendar.
Arizona Public Service	Disagree	TO’s should be required to inspected annually. This needs to be in R3 which is stated above. This standard should be consistent so each utility is audited the same.

Organization	Yes or No	Question 3 Comment
FirstEnergy Corp	Disagree	We do not agree with the parenthetical phrase "(as measured in line miles)". Entities may utilize other forms of measurement such as “corridor miles”. The standard should allow the TO to define its own measurement technique and then the VSL for this requirement would be based on a percentage of how much of the TO’s transmission system was missed per the measurement technique defined by the TO. We suggest removing the parenthetical phrase "of all applicable lines (as measured in line miles)" from Req. R3. and add a new subpart of Req. R1 requiring the TO, in its TVMP, to document its method of measuring the applicable lines to be maintained. Corresponding changes to the VSLs are also needed per this proposed revision. The VLS could be revised to read "... inspected greater than x% but less than y% of the Transmission Owner defined measurement technique as defined in sub-part 1.x"
Northern Indiana Public Service Company	Disagree	While I agree with the minimum interval of once a year for vegetation inspections, I have real concerns about using line miles for determining violation severity levels. We conduct vegetation inspections by R.O.W. corridor rather than by circuit or circuit line miles. Multiple circuits or segments of multiple circuits can exisit within the same R.O.W. complicating any calculation of how many line miles are inspected versus not inspected. How about using R.O.W. miles rather than circuit line miles for determining the V.S.L.?
Xcel Energy	Disagree	Xcel Energy does not disagree with the language of R3, however suggests that the referenced footnote 4 be modified to include “species epidemics,” such as bark beetles. It is proposed that footnote 4 have the term “species epidemics” inserted after “landslides” and before “wind shear.”
ISO/RTO Council		The SRC has no comment on this question.

4. As stated in the background information above, in response to industry comments, the Requirement for preventing vegetation encroachments (the new R4) is revised. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Organization	Yes or No	Question 4 Comment
Entegra Power Group LLC		No comment
American Electric Power	Agree	
Arizona Public Service	Agree	
Bonneville Power Administration	Agree	
Central Maine Power an Energy East Company	Agree	
Georgia Transmission Corporation	Agree	
Hydro One Networks inc.	Agree	
Lee County Electric Cooperative	Agree	
National Grid	Agree	
New Brunswick Power Transmission	Agree	
Northeast Utilities	Agree	
Northern Indiana Public Service Company	Agree	

Organization	Yes or No	Question 4 Comment
Oncor Electric Delivery	Agree	
ReliabilityFirst Corporation	Agree	
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tampa Electric Company	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Transmission Owner	Agree	
TVA	Agree	
TVA	Agree	
TVA	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
FirstEnergy Corp	Agree	Although we agree with this requirement, we want to point out a potential concern with double violations between R4 and either R5, R6, R7, or R8. Technically if at any point in real-time you violate one of the requirements R5 through R8, you have also violated R4. The SDT may want to consider adding a clarifying statement in R4 to alleviate a double violation such as "This requirement is not applicable when either R5, R6, R7, or R8 is violated".

Organization	Yes or No	Question 4 Comment
ISO New England Inc.	Agree	Falling vegetation should be an exception to an encroachment but a clarification is needed to confirm that any falling tree that gets lodged into another tree and violates the MVCD in real time is also included as part of the falling vegetation exception. Also, if a line is operating beyond its Emergency Rating due to system conditions, encroachments of the MVCD should not be considered a violation of R6. Request that additional clarification be made between the relationship of R1.6 and R4. R1.6 is a documentation requirement that requires that the TVMP specify strategies to ensure that the MVCD clearances are never violated under all operating/rated conditions. R4 is an implementation requirement that makes it a violation to encroach upon the MVCD in real time only. So if we had a situation where there would have been an MVCD encroachment if the conductor was at its lowest position (maximum sag) but, at the time of the observation, the conductor was at a higher position (not at maximum sag), our understanding is that there would be no violation of either R1.6 or R4 since the real time observation determined that the vegetation clearance was greater than the MVCD. This assumes that the strategies required under R1.6 are included in the TVMP.Clarification is needed for what is meant by "...as observed in real-time operating between no-load and their Rating."
Orange and Rockland Utilities, Inc.	Agree	ORU agrees that falling vegetation should be an exception to an encroachment but would like clarification to confirm that any falling tree that gets lodged into another tree and violates the MVCD in real time is also included as part of the falling vegetation exception. Also, if a line is operating beyond its Emergency Rating due to system conditions, encroachments of the MVCD should not be considered a violation of R6. ORU is requesting that additional clarification be made between the relationship of R1.6 and R4. R1.6 is a documentation requirement that requires that the TVMP specify strategies to ensure that the MVCD clearances are never violated under all operating/rated conditions. R4 is an implementation requirement that makes it a violation to encroach upon the MVCD in real time only. So if we had a situation where there would have been an MVCD encroachment if the conductor was at its lowest position (maximum sag) but, at the time of the observation, the conductor was at a higher position (not at maximum sag), our understanding is that there would be no violation of either R1.6 or R4 since the real time observation determined that the vegetation position was greater than the MVCD. This assumes that the strategies required under R1.6 are included in the TVMP.
PacifiCorp	Agree	PacifiCorp suggests inserting "by a qualified observer" after "observed." Otherwise, utilities could be held accountable to train all their workers who might casually encounter vegetation conditions in their work or commutes.
Southern California Edison Company	Agree	SCE generally agrees with the language of the requirement, but believes that the appropriate Violation Risk Factor is "Lower," rather than "Medium." SCE believes that an encroachment, in and of itself, does not necessarily rise to a level of significance that should require self-reporting, nor should such an occurrence necessarily subject the utility to an investigation with potential adverse findings and penalties. Considering the

Organization	Yes or No	Question 4 Comment
		purpose of the standard and the imprecise nature of vegetation management activities, the standard may be overly strict. Further, due to the resistance of certain land owners and/or agency officials to allowing utilities to prune beyond the prescribed minimum tree-to-line clearances, SCE asks the Drafting Team consider changing the term “Minimum Vegetation Clearance Distances” to “Critical Vegetation Clearance Distances".
Xcel Energy	Disagree	(a) Xcel Energy incorporates its response to number 3 above regarding footnote 4, alternatively, footnote 5 could be modified in a similar fashion to include “species epidemics” between “logging” and “animal severing tree.” (b) Xcel Energy suggests that the phrase “Minimum Vegetation Clearance Distances” (MVCD) be changed to “Critical Clearance Distance.” The use of the word “minimum” creates problems for Transmission Owners when dealing with land owners regarding the necessary vegetation management which is to take place on the subject property. “Minimum” creates difficulties in explaining to a land owner why any additional clearance need be obtained. That difficulty would be substantially lessened with the use of a term such as “critical,” which more readily lends itself to an additional distance such that the vegetation never approaches the critical distance.(c) Xcel Energy urges the insertion of “by a qualified observer” after “observed.” Otherwise, a Transmission Owner could have a violation as a result of a drive-by glance by an office clerical worker.
MRO NERC Standards Review Subcommittee	Disagree	A. The MRO NSRS suggests that the phrase “Minimum Vegetation Clearance Distances” (MVCD) be changed to “Critical Clearance Distance.” The use of the word “minimum” creates problems for Transmission Owners when dealing with land owners regarding the necessary vegetation management which is to take place on its easements. “Minimum” creates difficulties in explaining to a land owner why any additional clearance needs to be obtained. That difficulty would be substantially lessened with the use of a term such as “critical”, which more readily lends itself to an additional distance such that the vegetation never approaches the critical distance.B. The MRO NSRS agrees with the intent of including events that would define exceptions for requirements to comply with FAC-003. As an alternative to the approach in the draft Standard of using footnotes, the MRO NSRS recommends that the SDT consider adding a generic “force majeure” statement in the applicability section more specifically stating that companies will not be subject to compliance requirements to the extent that events or circumstances beyond their control limit or prevent their abilities to perform. Here’s an example:Compliance with this standard will not apply should there exist an occurrence, non-occurrence, or other set of circumstances that are beyond the reasonable control of a Registered Entity subject to this Reliability Standard, and are not caused by the fault or negligence of the Registered Entity, including acts of God, strike, flood, drought, earthquake, storm, fire, hurricane, tornado, landslides, logging activities, animals severing trees, lightning, epidemic, war, riot, civil disturbance, sabotage, vandalism, terrorism, or action or inaction by any Governmental Authority or individual that restricts or prevents performance to comply with this Reliability Standard.C. R4 states that “Each Transmission Owner shall prevent encroachment of vegetation into the Minimum Vegetation Clearance Distances (MVCD) listed in FAC-003-2 - Attachment 1........” The MRO NSRS requests the Standard clarify how MVCDs will be interpolated for

Organization	Yes or No	Question 4 Comment
		altitudes not specifically defined in Table 1.
Salt River Project	Disagree	Although the replacement of the Critical Clearance Zone (CCZ) in R4 is an improvement, we still question the use of the Gallet Equation. Although the Gallet Equation is more definitive than using IEEE 516 as identified in the current standard, we question from an engineering perspective as to how and why this method was chosen for vegetation management. The Gallet Equation is a well known method of computing the required strike distance for proper insulation coordination. It is our understanding that the purpose is for designing towers, to define the “tower window” or opening inside of a tower under normal conditions. Because this is not a method designed specifically for vegetation management, there is no basis for applying this to vegetation management. It is recommended that testing be done to justify this method to be used for vegetation management. We would find it definitive to substantiate the calculated equation assertions with test data from actual energized flashover distances to vegetation. The testing ought to include dry and misting conditions at 200+ kilovolt levels on a sampling of fresh cut common vegetation types. Reputable EHV testing facilities where such tests can be performed exist within the United States and Canada.
Platte River Power Authority Vegetation Management Group	Disagree	As the requirement is written it is a violation of the requirement when a possible encroachment of the MVCD is discovered through inspections and such an encroachment should be self-reported to the RE. This is inconsistent with the purpose of the standard to prevent vegetation-related outages that can result in Cascading. We would suggest that appropriate action be taken to correct encroachment of the MVCD but that it wouldn’t be a violation of the requirement until a Sustained Outage has occurred or the imminent treat process has been implemented. R4 refers to observation in real-time. This actual field observation of the MVCD between no-load and its Rating is too subjective and lends itself to too much interpretation by the inspector especially in light of the fact that it could be a self-reported violation if the MVCD is encroached.
Associated Electric Cooperative, Inc.	Disagree	Associated Electric Cooperative Inc. suggests the third exception bullet under R4 is unclear. Is the exception meant to address vegetation from either inside or outside the ROW that: 1) may pass through the MVCD while falling; or, 2) has fallen and may now encroach into the MVCD from its new steady state position?
American Transmission Company	Disagree	ATC agrees with the intent of including events that would define exceptions for requirements to comply with FAC-003. As an alternative to the approach in the draft Standard of using footnotes, ATC recommends that the SDT consider adding a generic force majeure statement in the applicability section more specifically stating that companies will not be subject to compliance requirements to the extent that events or circumstances beyond their control limit or prevent their abilities to perform. Here’s an example:Compliance with this standard will not apply should there exist an occurrence, non-occurrence, or other set of circumstances that are beyond the reasonable control of a Registered Entity subject to this Reliability Standard, and are not caused by the fault or negligence of the Registered Entity, including acts of God, strike, flood, drought, earthquake, storm, fire, hurricane, tornado, landslides, logging activities, animals severing

Organization	Yes or No	Question 4 Comment
		trees, lightning, epidemic, war, riot, civil disturbance, sabotage, vandalism, terrorism, or action or inaction by any Governmental Authority or individual that restricts or prevents performance to comply with this Reliability Standard.Also, R 4 states that “Each Transmission Owner shall prevent encroachment of vegetation into the Minimum Vegetation Clearance Distances (MVCD) listed in FAC-003-2 - Attachment 1........”ATC requests the Standard clarify how MVCDs will be interpolated for altitudes not specifically defined in Table 1.
Consolidated Edison Company of New York Inc.	Disagree	CECONY agrees that falling vegetation should be an exception to an encroachment but would like clarification to confirm that any falling tree that gets lodged into a stable tree and pushes the stable tree beyond the MVCD in real time is also included as part of the falling vegetation exception. CECONY is requesting that additional clarification be made between the relationship of R1.6 and R4. R1.6 is a documentation requirement that requires that the TVMP specify strategies to ensure that the MVCD clearances are never violated under all operating/rated conditions. R4 is an implementation requirement that makes it a violation to encroach upon the MVCD in real time only. So if we had a situation where there would have been an MVCD encroachment if the conductor was at its lowest position (maximum sag) but, at the time of the observation, the conductor was at a higher position (not at maximum sag), our understanding is that there would be no violation of either R1.6 or R4 since the real time observation determined that the vegetation position was greater than the MVCD. This assumes that the strategies required under R1.6 are included in the TVMP.
Idaho Power Company	Disagree	Change the Minimum Vegetation Clearance Distance (MVCD) to Critical Vegetation Clearance Distance (CVCD) to indicate a higher level of importance when dealing with federal agencies and reluctant property owners. Provide a better definition for the term ‘Real Time’. Include in this definition the use of technology to determine if an imminent threat exists to help minimize real time patrols. In footnote 5 provide more information on what agricultural activities includes.
Vegetation Management Team	Disagree	Disagree with R4 and M4. As explained in the comment for R1, encroachments should also be addressed via a pre-determined process before becoming a violation of the standard. Therefore, we suggest the following changes be made to the requirements: R4: Each Transmission Owner shall [REMOVE: prevent encroachment of vegetation into the] implement its vegetation encroachment response process or procedure when the Transmission Owner has actual knowledge of such an encroachment on any Minimum Vegetation Clearance Distances (MVCD) listed in FAC-003-2-Attachment 1 [REMOVE: for its applicable lines as observed in real-time operating between no-load and their Rating.], obtained through implementation of the annual work plan and the TVMP. M4: The Transmission Owner has evidence [REMOVE: from inspections that indicate there was no vegetation encroachment into the Minimum Vegetation Clearance Distances listed in FAC-003-2-Attachment 1 for its applicable lines as observed in real-time operating between no-load and their Rating, considering exceptions.] of the implementation of its vegetation encroachment process or procedure showing actions taken and dates of performance.Likewise, we suggest the following be made to

Organization	Yes or No	Question 4 Comment
		the Violation Severity Levels chart: Severe: [REMOVE: The Transmission Owner has failed to prevent vegetation from encroaching into the minimum vegetation clearance distance.] The Transmission Owner did not implement its vegetation encroachment response process or procedure when the Transmission Owner had actual knowledge of such an encroachment on any Minimum Vegetation Clearance Distances (MVCD) listed in FAC-003-2-Attachment 1 obtained through normal operating practices.
Hydro-Quebec TransEnergie (HQT)	Disagree	Falling vegetation should be an exception to an encroachment but a clarification is needed to confirm that any falling tree that gets lodged into another tree and violates the MVCD in real time is also included as part of the falling vegetation exception. Also, if a line is operating beyond its Emergency Rating due to system conditions, encroachments of the MVCD should not be considered a violation of R6. Request that additional clarification be made between the relationship of R1.6 and R4. R1.6 is a documentation requirement that requires that the TVMP specify strategies to ensure that the MVCD clearances are never violated under all operating/rated conditions. R4 is an implementation requirement that makes it a violation to encroach upon the MVCD in real time only. So if we had a situation where there would have been an MVCD encroachment if the conductor was at its lowest position (maximum sag) but, at the time of the observation, the conductor was at a higher position (not at maximum sag), our understanding is that there would be no violation of either R1.6 or R4 since the real time observation determined that the vegetation clearance was greater than the MVCD. This assumes that the strategies required under R1.6 are included in the TVMP.Clarification is needed for what is meant by “...as observed in real-time operating between no-load and their Rating.”
Independent Electricity System Operator	Disagree	Falling vegetation should be an exception to an encroachment but a clarification is needed to confirm that any falling tree that gets lodged into another tree and violates the MVCD in real time is also included as part of the falling vegetation exception. Also, if a line is operating beyond its Emergency Rating due to system conditions, encroachments of the MVCD should not be considered a violation of R6. Request that additional clarification be made between the relationship of R1.6 and R4. R1.6 is a documentation requirement that requires that the TVMP specify strategies to ensure that the MVCD clearances are never violated under all operating/rated conditions. R4 is an implementation requirement that makes it a violation to encroach upon the MVCD in real time only. So if we had a situation where there would have been an MVCD encroachment if the conductor was at its lowest position (maximum sag) but, at the time of the observation, the conductor was at a higher position (not at maximum sag), our understanding is that there would be no violation of either R1.6 or R4 since the real time observation determined that the vegetation clearance was greater than the MVCD. This assumes that the strategies required under R1.6 are included in the TVMP.Clarification is needed for what is meant by “...as observed in real-time operating between no-load and their Rating.”
Northeast Power Coordinating Council--RSC	Disagree	Falling vegetation should be an exception to an encroachment but a clarification is needed to confirm that any falling tree that gets lodged into another tree and violates the MVCD in real time is also included as part of the falling vegetation exception. Also, if a line is operating beyond its Emergency Rating due to system

Organization	Yes or No	Question 4 Comment
		conditions, encroachments of the MVCD should not be considered a violation of R6. Request that additional clarification be made between the relationship of R1.6 and R4. R1.6 is a documentation requirement that requires that the TVMP specify strategies to ensure that the MVCD clearances are never violated under all operating/rated conditions. R4 is an implementation requirement that makes it a violation to encroach upon the MVCD in real time only. So if we had a situation where there would have been an MVCD encroachment if the conductor was at its lowest position (maximum sag) but, at the time of the observation, the conductor was at a higher position (not at maximum sag), our understanding is that there would be no violation of either R1.6 or R4 since the real time observation determined that the vegetation clearance was greater than the MVCD. This assumes that the strategies required under R1.6 are included in the TVMP.Clarification is needed for what is meant by “...as observed in real-time operating between no-load and their Rating.”
JEA	Disagree	I object to the zero defect concept. I realize that there is pressure from FERC, however Section 215 of the FPA specifically states "The Commission shall give due weight to the technical expertise of the Electric Reliability Organization with respect to the content of a proposed standard or modification to a reliability standard..." The technical feasibility of 0 defects is questionable. The industry should develop an aggressive but acheivable performance level for preventing encroachments etc.
CenterPoint Energy	Disagree	It is not clear how R4’s last bullet, “Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from falling vegetation” is observable as an exception, and the Technical Reference does not clarify it either. It would appear that if a tree branch (e.g. wind-blown or fallen branch debris) was observed hanging on the conductor, but was not causing an outage, that it would be considered an exception. The bullet item should be clarified or deleted.
US Bureau of Reclamation	Disagree	It is not clear why wind blown debris is not listed as an exception. It is also not clear why these exemptions are needed as they are not vegeetation encroachments.
North Carolina Electric Membership Corporation	Disagree	NCEMC has concerns about the enforcement of the requirement.There seems to be an issue with enforcement of the third exemption if any vegetation falls and lodges to create a MVCD violation from inside or outside the ROW.
Pacific Gas and Electric Co.	Disagree	PG&E agrees in principal with R5 but disagrees with the exception for human activity noted in footnote (5), specifically aboriculture, horticulture or agricultural activities. This exception is overly broad and could be interpreted as exempting certian activities (such as planting orchards, xmas tree farms, community tree plantings, etc.) from the standard and will invite legal challenges to the TO’s right to perform vegetation management. PG&E proposes alternative language to the exception as follows: Examples include, but are not limited to, logging, animal severing tree, vehicle contact with tree, digging or removal of tree or new

Organization	Yes or No	Question 4 Comment
		plantings between inspection cycles where the TO does not have actual knowledge. As an alternative, add a generic force majeure statement as described in Q18 #2.
Public Service Co. of New Mexico	Disagree	PNM is not in favor of the current MVCD table 1. This will not provide clarity to the field personnel as to clearance distances. It could cause increasing confusion as to how much clearance needs to be obtained at the time of work. Clearance 1 and 2 were much clearer in that respect.
SCE&G	Disagree	SCE&G has concerns about the enforcement of the requirement. There seems to be an issue with enforcement of the third exemption if any vegetation falls and lodges to create a MVCD violation from inside or outside the ROW.
Duke Energy	Disagree	Since this standard already includes other requirements to implement a transmission vegetation management program to maintain the defined clearances, as well as an imminent threat process or procedure to avoid sustained outages, we believe that Requirement R4 provides no additional reliability benefit and should be deleted. If it is decided that this requirement must be retained, then it needs to be re-written such that it is a performance-based requirement with graduated VSLs. As currently written, this requirement is a binary requirement which carries a single VSL which can only be “Severe”. Such a zero-tolerance approach to preventing encroachments does not provide industry with a reasonable opportunity for success, absent the establishment of overly-aggressive and costly vegetation management programs that carry minimal additional reliability benefit. A performance-based requirement should be developed relative to some metric such as line-mile exposure that will promote high quality vegetation management, optimization of the reliability cost/benefit relationship and deliver the overall end result of improved reliability to the system. The performance-based requirement should be structured for a graduated VSL. Due to this requirement being focused on preventing encroachments rather than sustained outages, we believe that a zero tolerance approach is not warranted to improve reliability.In addition, the third exemption is not clear as it relates to falling vegetation. For example, how would an event be viewed if a tree lodges into another tree or hits another tree causing it to lean such that it is within the MVCD?
Pepco Holdings, Inc - Affiliates (PHI)	Disagree	The definition of Rating includes the word -limits- implying that Rating is a plural term. Does the SDT mean the highest sustained limit (10 minutes? 30 minutes? 24 hours?...)?
Manitoba Hydro	Disagree	The phrase “Minimum Vegetation Clearance Distances” (MVCD) should be changed to “Critical Clearance Distance.” The use of the word “minimum” creates problems for Transmission Owners when dealing with land owners regarding the necessary vegetation management which is to take place on the subject property. “Minimum” creates difficulties in explaining to a land owner why any additional clearance need be obtained. That difficulty would be substantially lessened with the use of a term such as “critical,” which more readily

Organization	Yes or No	Question 4 Comment
		lends itself to an additional distance such that the vegetation never approaches the critical distance.Insert “by a qualified observer” after “observed.” Otherwise, a Transmission Owner could have a violation as a result of a drive-by glance by an office clerical worker.
E.ON U.S.	Disagree	The standard does not specify what is meant by “off/on ROW”.E.ON U.S. questions how NERC plans on enforcing the third bullet
BC Transmission Corporation	Disagree	The standard should limit itself to the prevention of outages. If vegetation encroaches within the MVCD and the TO effectively implements the imminent threat process to prevent an outage this should not be a violation. Additionally this requirement will be very difficult to audit and enforce.
Puget Sound Energy	Disagree	The term, Minimum Vegetation Clearance Distance (MVCD) does not invoke the critical dangerous nature of the close distance to the conductor. A more impactful term such as “critical” would be more appropriate.
Ameren	Disagree	The third bullet point on "falling vegetation" is unclear. Would like to see this clarify whether on ROW and/or off ROW falling trees.
SERC Vegetation Managment Sub-committee (VMS)	Disagree	The VMS has concerns about the enforcement of the requirement.There seems to be an issue with enforcement of the third exemption if any vegetation falls and lodges to create a MVCD violation from inside or outside the ROW.
Progress Energy Carolinas, Inc.	Disagree	There is an issue with the wording of the third exemption when any vegetation from outside the ROW falls and lodges to create a MVCD violation. The wording as proposed could be interpreted as non-compliance due to vegetation from outside of the ROW.
Entergy Services, Inc	Disagree	There may be an issue of the third exemption if vegetation falls and lodges to create a MVCD violation from inside or outside the Right of Way.
Tucson Electric Power Company	Disagree	We feel that the use of the word “Minimum” in Minimum Vegetation Clearance Distance should be “Critical”. Governing/Managing land agencies could use the word Minimum, as an allowable limit argument against the utility and deny needed permissions work as long as there is more than the minimum clearance in on the line. The use of the word critical would indicate the need for additional buffer distance to prevent vegetation caused outages. Additionally is the exception to the rule about falling vegetation from inside or outside the ROW/Easement?

Organization	Yes or No	Question 4 Comment
Nebraska Public Power District	Disagree	Xcel Energy urges the insertion of “by a qualified observer” after “observed.” Otherwise, a Transmission Owner could have a violation as a result of a drive-by glance by an office clerical worker.
ISO/RTO Council		The SRC has no comment on this question.

5. As stated in the background information above, in response to industry comments, the Requirement for preventing Sustained Outages due to grow-ins on IROL or Major WECC Transfer Paths (the new R5) is developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Organization	Yes or No	Question 5 Comment
Entegra Power Group LLC		No comment
Ameren	Agree	
American Electric Power	Agree	
Arizona Public Service	Agree	
Associated Electric Cooperative, Inc.	Agree	
Bonneville Power Administration	Agree	
CenterPoint Energy	Agree	
Central Maine Power an Energy East Company	Agree	
Consolidated Edison Company of New York Inc.	Agree	
Duke Energy	Agree	
E.ON U.S.	Agree	
Entergy Services, Inc	Agree	
Georgia Transmission Corporation	Agree	

Organization	Yes or No	Question 5 Comment
Hydro One Networks inc.	Agree	
Idaho Power Company	Agree	
Lee County Electric Cooperative	Agree	
National Grid	Agree	
Nebraska Public Power District	Agree	
NERC Standards Review Subcommittee	Agree	
New Brunswick Power Transmission	Agree	
North Carolina Electric Membership Corporation	Agree	
Northeast Utilities	Agree	
Northern Indiana Public Service Company	Agree	
Oncor Electric Delivery	Agree	
PacifiCorp	Agree	
Platte River Power Authority Vegetation Management Group	Agree	
Progress Energy Carolinas, Inc.	Agree	
Public Service Co. of New	Agree	

Organization	Yes or No	Question 5 Comment
Mexico		
ReliabilityFirst Corporation	Agree	
Salt River Project	Agree	
SCE&G	Agree	
SERC Vegetation Managment Sub-committee (VMS)	Agree	
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Transmission Owner	Agree	
TVA	Agree	
TVA	Agree	
TVA	Agree	
Vegetation Management Team	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	

Organization	Yes or No	Question 5 Comment
Orange and Rockland Utilities, Inc.	Agree	ORU agrees that, if a line is operating beyond its Emergency Rating due to system conditions, encroachments of the MVCD should not be considered a violation of R5.
Southern California Edison Company	Agree	SCE generally agrees with the assigned Violation Risk Factor for lines that are an element of an IROL or a WECC transfer path. SCE believes that the bulleted exceptions listed in the new R5 are appropriate.
Tampa Electric Company	Agree	The white paper, on page 33, paragraph 4, defines a sustained outage as vegetation related event, if it occurs within the specified rating of the facility. If the conductor is operating above its rating it states that this “would not be classified as a vegetation related sustained outage under the standard.” If this is so it needs to be stated and/or clarified in the standard itself.
American Transmission Company	Disagree	ATC recommends that the SDT consider the statements in the Technical Paper on pgs. 32-34; i.e. encroachment taking place while a line is operating beyond its rating is not a violation of this Requirement.
FirstEnergy Corp	Disagree	FE suggests a revision of Requirement R5.FE encourages the team to re-evaluate its approach to requirements R5 through R7 and consider changes that would remove the binary aspect of the requirements and permit a graded approach to the VSL structure for a non-compliance of the requirement. Our proposal is to incorporate aspects of R7 (blow in) and R8 (fall in) into both requirements R5 (grow-in IROL) and R6 (grow-in Non-IROL) so that R5 and R6 establish requirements for grow-in, blow-in and fall-in. The proposed requirement for R5 would read: "Each Transmission Owner shall prevent Sustained Outages of applicable lines that are identified as an element of an Interconnection Reliability Operating Limit (IROL) (or Major WECC Transfer Path) due to vegetation growing into a conductor operating between no-load and its Rating, due to the blowing together of a conductor and vegetation rooted within an ActiveTransmission Line Right of Way (operating within design blow-out conditions), or due to vegetation falling into a conductor with the following exceptions:"Similarly, the proposed R6 would read:"Each Transmission Owner shall prevent Sustained Outages of applicable lines that are not an element of an IROL (or major WECC Transfer Path) due to vegetation growing into a conductor operating between no-load and its Rating, due to the blowing together of a conductor and vegetation rooted within an Active Transmission Line Right of Way (operating within design blow-out conditions), or due to vegetation falling into a conductor with the following exceptions:"These requirement changes provide the flexibility needed to establish graded VSLs. FE’s proposed VSL levels are consistent with the reporting categories established in section D 1.5. The root of the requirement is "shall prevent Sustained Outages" and the VSL gauge of how much a VM program missed the mark would then be reflected in the type of vegetation contact. Therefore, we propose VSL levels for both Req. R5 and R6 as follows: grow-in (SEVERE VSL), a fall-in (MODERATE VSL),a blow-in (LOWER VSL).No changes to the Violation Risk Factors or Time Horizons for requirements R5 or R6 are proposed.If the proposal is accepted, conforming changes to the Measures are required.

Organization	Yes or No	Question 5 Comment
WECC	Disagree	I agree with the requiring the prevention of sustained outages due to grow-ins on an identified subsed of all transmission facilities. However, I am concerned over the use of the capitalized term Major WECC Transfer Paths. Because this is not a defined term in the NERC Glossary and is not the complete name of any WECC listing,I suggest the phrase (or Major WECC Transfer Paths)be changed to (or major transfer paths in the Western Interconnection as identified by WECC). In the alternative, the full name of the dcoument known as Table 2 that is referred to in the second draft is "Major WECC Transfer Paths in the Bulk Electric System". Is there going to be a problem with the capitalized term if a definition is not developed, knowing that the capitalized term refers to an existing document?
Tucson Electric Power Company	Disagree	In the footnote examples of human activities, there is an exemption for agricultural activities. The planting of and maintenance of orchards is an agricultural activity that should specifically address as not applying in this exemption.
US Bureau of Reclamation	Disagree	It is not clear what Natural disasters or human activity have to do with growing vegetation. Also it is not clear why falling vegetation or wind blown debris are not listed as exemptions.
Pacific Gas and Electric Co.	Disagree	PG&E agrees in principal with R5 but disagrees with the exception for human activity noted in footnote (5), specifically aboriculture, horticulture or agricultural activities. This exception is overly broad and could be interpreted as exempting certian activities (such as planting orchards) from the standard and will invite legal challenges to the TO’s right to perform vegetation management. PG&E proposes alternative language to the exception as follows: Examples include, but are not limited to, logging, animal severing tree, vehicle contact with tree, digging or removal of tree or new plantings between inspection cycles where the TO does not have actual knowledge. As an alternative, add a generic force majeure statement as described in Q18 #2.
Xcel Energy	Disagree	Please see our comments above concerning footnotes 4 & 5.
JEA	Disagree	Please see the comment to question 4.
Pepco Holdings, Inc - Affiliates (PHI)	Disagree	R5 also uses the term Rating. See comment to Q4.
Puget Sound Energy	Disagree	Regional differences should be addressed through regional standards. The reference to Major WECC Transfer Paths should be removed and allow the region to determine whether to expand the implication of the standard.

Organization	Yes or No	Question 5 Comment
Hydro-Quebec TransEnergie (HQT)	Disagree	The introduction of IROL introduces an unnecessary level of complexity in the standard. The facilities being addressed in the standard impact the Bulk Electric System, and the additional "drilling down" is not needed. R5 and R6 seems to have been introduced just to have different violation risk factor for different types of lines. Delete R5 or R6 after removing the IROL concept.
Independent Electricity System Operator	Disagree	The introduction of IROL introduces an unnecessary level of complexity in the standard. The facilities being addressed in the standard impact the Bulk Electric System, and the additional "drilling down" is not needed.
ISO New England Inc.	Disagree	The introduction of IROL introduces an unnecessary level of complexity in the standard. The facilities being addressed in the standard impact the Bulk Electric System, and the additional "drilling down" is not needed.
Northeast Power Coordinating Council--RSC	Disagree	The introduction of IROL introduces an unnecessary level of complexity in the standard. The facilities being addressed in the standard impact the Bulk Electric System, and the additional "drilling down" is not needed.
BC Transmission Corporation	Disagree	The IROL is not properly defined in this standard it is hard to agree with this requirement if we do not know exactly what this means. Please put foot note #7 back into the document. Why single out WECC and not other reliability councils.
Manitoba Hydro	Disagree	The SDT should consider the statements in the Technical Paper on pgs. 32-34 that encroachment taking place if a line is operating beyond its rating would not be a violation of the Requirement.
ISO/RTO Council		The SRC has no comment on this question.

6. As stated in the background information above, in response to industry comments, the Requirement for preventing Sustained Outages due to grow-ins on non-IROL or Major WECC Transfer Paths (the new R6) is developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Organization	Yes or No	Question 6 Comment
Entegra Power Group LLC		No comment
Ameren	Agree	
American Electric Power	Agree	
Arizona Public Service	Agree	
Associated Electric Cooperative, Inc.	Agree	
BC Transmission Corporation	Agree	
Bonneville Power Administration	Agree	
CenterPoint Energy	Agree	
Central Maine Power an Energy East Company	Agree	
Consolidated Edison Company of New York Inc.	Agree	
E.ON U.S.	Agree	
Entergy Services, Inc	Agree	

Organization	Yes or No	Question 6 Comment
Georgia Transmission Corporation	Agree	
Hydro One Networks inc.	Agree	
Idaho Power Company	Agree	
Lee County Electric Cooperative	Agree	
National Grid	Agree	
Nebraska Public Power District	Agree	
NERC Standards Review Subcommittee	Agree	
New Brunswick Power Transmission	Agree	
North Carolina Electric Membership Corporation	Agree	
Northeast Utilities	Agree	
Northern Indiana Public Service Company	Agree	
Oncor Electric Delivery	Agree	
Orange and Rockland Utilities, Inc.	Agree	
PacifiCorp	Agree	

Organization	Yes or No	Question 6 Comment
Pepco Holdings, Inc - Affiliates (PHI)	Agree	
Platte River Power Authority Vegetation Management Group	Agree	
Progress Energy Carolinas, Inc.	Agree	
Public Service Co. of New Mexico	Agree	
Puget Sound Energy	Agree	
Salt River Project	Agree	
SCE&G	Agree	
SERC Vegetation Managment Sub-committee (VMS)	Agree	
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Transmission Owner	Agree	
Tucson Electric Power Company	Agree	
TVA	Agree	

Organization	Yes or No	Question 6 Comment
TVA	Agree	
TVA	Agree	
Vegetation Management Team	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
ReliabilityFirst Corporation	Agree	Do we need R5 and R6? The requirements are same whether the line is an IROL or not.
ISO New England Inc.	Agree	Refer to the response to Question 5.
Tampa Electric Company	Agree	Same response as question 5.
Southern California Edison Company	Agree	SCE generally agrees with the assigned Violation Risk Factor for lines that are not an element of an IROL or a WECC transfer path. SCE believes that the bulleted exceptions listed in the new R6 are appropriate.
American Transmission Company	Disagree	ATC recommends that the SDT consider the statements in the Technical Paper on pgs. 32-34; i.e. encroachment taking place while a line is operating beyond its rating is not a violation of this Requirement.
FirstEnergy Corp	Disagree	FE suggests a revision of R6. See our response to Question 5 for further information.
US Bureau of Reclamation	Disagree	It is not clear what Natural disasters or wind blown debris have to do with growing vegetation. Also it is not clear why human or animal activity or falling vegetation are not listed as exceptions.
Pacific Gas and Electric Co.	Disagree	PG&E agrees in principal with R5 but disagrees with the exception for human activity noted in footnote (5), specifically aboriculture, horticulture or agricultural activities. This exception is overly broad and could be interpreted as exempting certian activities (such as planting orchards) from the standard and will invite legal challenges to the TO's right to perform vegetation management. PG&E proposes alternative language to the exception as follows: Examples include, but are not limited to, logging, animal severing tree, vehicle contact with tree, digging or removal of tree or new plantings between inspection cycles where the TO does not have

Organization	Yes or No	Question 6 Comment
		actual knowledge. As an alternative, add a generic force majeure statement as described in Q18 #2.
Xcel Energy	Disagree	Please see our comments above concerning footnotes 4 & 5.
JEA	Disagree	Please see the comment to question 4.
Independent Electricity System Operator	Disagree	Refer to the response to Question 5.
Northeast Power Coordinating Council--RSC	Disagree	Refer to the response to Question 5.
WECC	Disagree	same comment as for question 5. Agree with the concept, but concern over the term major WECC Transfer Paths (note that the word major is not capitalized in R6 but it is in R5. Suggest replaceing with the phrase (or major transfer paths in the Western Interconnection as identified by WECC)
Hydro-Quebec TransEnergie (HQT)	Disagree	See answer to Q5.
Manitoba Hydro	Disagree	The SDT should consider the statements in the Technical Paper on pgs. 32-34 that encroachment taking place if a line is operating beyond its rating would not be a violation of the Requirement.
Duke Energy	Disagree	This requirement needs to be re-written such that it is a performance-based requirement with graduated VSLs. As currently written, this requirement is a binary requirement which carries a single VSL which can only be “Severe”. This may drive overly-aggressive and costly vegetation management programs that carry minimal additional reliability benefit. A performance-based requirement should be developed relative to some metric such as line-mile exposure that will promote high quality vegetation management, optimization of the reliability cost/benefit relationship and deliver the overall end result of improved reliability to the system. The performance-based requirement may still be zero tolerance, but should be structured for a graduated VSL.
ISO/RTO Council		The SRC has no comment on this question.

7. As stated in the background information above, in response to industry comments, the Requirement for preventing Sustained Outages due to blowing together of vegetation and transmission line conductors (the new R7) is developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Organization	Yes or No	Question 7 Comment
Entegra Power Group LLC		No comment
Ameren	Agree	
American Electric Power	Agree	
BC Transmission Corporation	Agree	
Bonneville Power Administration	Agree	
Consolidated Edison Company of New York Inc.	Agree	
Georgia Transmission Corporation	Agree	
Hydro One Networks inc.	Agree	
Hydro-Quebec TransEnergie (HQT)	Agree	
Idaho Power Company	Agree	
Independent Electricity System Operator	Agree	
ISO New England Inc.	Agree	

Organization	Yes or No	Question 7 Comment
Lee County Electric Cooperative	Agree	
Manitoba Hydro	Agree	
National Grid	Agree	
Nebraska Public Power District	Agree	
NERC Standards Review Subcommittee	Agree	
New Brunswick Power Transmission	Agree	
Northeast Power Coordinating Council--RSC	Agree	
Northeast Utilities	Agree	
Oncor Electric Delivery	Agree	
Orange and Rockland Utilities, Inc.	Agree	
Pacific Gas and Electric Co.	Agree	
PacifiCorp	Agree	
Pepco Holdings, Inc - Affiliates (PHI)	Agree	
Platte River Power Authority Vegetation Management Group	Agree	

Organization	Yes or No	Question 7 Comment
Public Service Co. of New Mexico	Agree	
Puget Sound Energy	Agree	
ReliabilityFirst Corporation	Agree	
Salt River Project	Agree	
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Tucson Electric Power Company	Agree	
TVA	Agree	
TVA	Agree	
TVA	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Vegetation Management Team	Agree	Concerned about the term “design blow-out conditions”. Some natural disasters (hurricanes, wind shear, fresh gale, etc.) may have a lower threshold than “design blow-out.

Organization	Yes or No	Question 7 Comment
Northern Indiana Public Service Company	Agree	Have concerns about T.O.'s determining what is "active" and "inactive" R.O.W. which are explained in Question 1 comments.
Southern California Edison Company	Agree	SCE generally agrees with the content of the new R7, but believes it could be combined with the new R8 into a single requirement (a revised new R7). It appears to SCE that both bulleted exceptions listed in the new R8 can also be applied to the new R7. Please see SCE's response to Question 8 below.
E.ON U.S.	Disagree	: E.ON U.S. requests that the SDT add language specifically excluding vegetation outside of an active ROW that could potentially blow into the conductor
North Carolina Electric Membership Corporation	Disagree	An issue exists, as currently worded, in that it does not exclude vegetation entirely off the ROW, under normal weather conditions, that could be blown into the conductor.
SCE&G	Disagree	An issue exists, as currently worded, in that it does not exclude vegetation entirely off the ROW, under normal weather conditions, that could be blown into the conductor.
SERC Vegetation Managment Sub-committee (VMS)	Disagree	An issue exists, as currently worded, in that it does not exclude vegetation entirely off the ROW, under normal weather conditions, that could be blown into the conductor.
Entergy Services, Inc	Disagree	As currently written, the Standard does not exclude vegetation entirely off the Right of Way, under normal weather conditions, that could be blown into the conductor.
Associated Electric Cooperative, Inc.	Disagree	Associated Electric Cooperative Inc agrees with the intent of R7. Perhaps the clarity could be improved by rewording, such as: “Each Transmission Owner shall prevent Sustained Outages6 of applicable lines due to the blowing together of a conductor and vegetation from within an Active Transmission Line Right of Way (operating within design blow-out conditions) with the following exception: [Violation Risk Factor - Medium][Time Horizon - Real Time]o Sustained Outages of applicable lines that result from natural disasters4 or wind-blown debris.
American Transmission Company	Disagree	ATC requests the SDT to clarify “wind-blown debris”. ATC believes the definition should include branches and/or trunks partially severed from the tree.
FirstEnergy Corp	Disagree	FE suggests a removal of R7. See our response to Question 5 for further information.
Tampa Electric Company	Disagree	In the white paper, page 35, paragraph 2, it states that if the conductor is operating above its rating it” would

Organization	Yes or No	Question 7 Comment
		not be classified as vegetation related sustained outage under the standard.” If this is so it needs to be stated and/or clarified in the standard itself. In addition, on page 35, 3rd paragraph, last sentence of the white paper it states,” Additionally, sustained outages due to wind-blown debris, such as large limbs and branches, separated tree tops, etc., are exempt from this standard.” Again if this is so it needs to be stated in the standard. Question for clarification: If the debris that falls is from a tree within the active transmission line ROW is it a violation?
US Bureau of Reclamation	Disagree	It is not clear why Natural disasters or wind blown debris have to do with vegetation blowing together with transmission lines. Also it is not clear why human or animal activity or falling vegetation are not listed as exemptions.
Central Maine Power an Energy East Company	Disagree	Note that R7 applies only to trees growing within the active right of way. Suggest that the standard clearly explain this concept.
Progress Energy Carolinas, Inc.	Disagree	Off ROW vegetation blowing into conductors is nothing more than off ROW vegetation “falling into the line” without permanent deformation of the vegetation (i.e., breaking/uprooting). Since the original design of the line did not require the off ROW vegetation to be removed, off ROW vegetation should not be included in the requirement.R8 as it is currently worded, “Each Transmission Owner shall prevent Sustained Outages of applicable lines due to the blowing together of vegetation and a conductor within an Active Transmission Line Right of Way (operating within design blow-out conditions) with the following exception:” should be reworded as follows... “...due to the blowing together of a conductor and vegetation rooted within the Active Transmission Line Right of Way...)
Xcel Energy	Disagree	Please see our comments above concerning footnotes 4 & 5.
JEA	Disagree	Please see the comment to question 4.
CenterPoint Energy	Disagree	R7 refers to “Active Transmission Line Right of Way” which is not defined as to its limits within the Standard. The SDT has indicated in its response to 1st Draft Comments from CenterPoint Energy that the “...Transmission Owner is responsible for defining the Active Transmission Line Right of Way.” However, that defining clause is not included in the current definition. CenterPoint Energy recommends deleting the phrase, “within an Active Transmission Line Right of Way”, deleting the phrase, “operating within design blow-out conditions”, and revising R7 to read, “Each Transmission Owner shall prevent Sustained Outages of applicable lines due to the blowing together of vegetation and a conductor operating within its designed sway under rated conditions with the following exceptions...”. The terms used in R1 of “sag” and “sway” should be used consistently. R1.6 already requires that maintenance strategies ensure that the MVCD is never violated

Organization	Yes or No	Question 7 Comment
		and “consider the sag and sway of the conductor throughout is operating range and under rated conditions”. This requirement by itself defines the airspace that must be maintained to prevent a Sustained Outage. R7 requires no specific definition of a right of way because R1 already defines the necessary minimum clearance to be maintained at all times.
Transmission Owner	Disagree	This requirement is not congruent with the purpose of this standard. The standard was enacted as a result of the North East Blackout and a history of grid blackouts in which the growth of trees below conductors under load contributed to the situation. Trees blowing into the conductor create no more risk to cascading than causes such as lightning or foreign interference. This requirement should be removed from the standard.
Arizona Public Service	Disagree	This requirement is too vague and needs more clarity. Vegetation in the easement width or permitted ROW shall not blow into the conductors resulting in an outage. If a utility has rights to maintain vegetation there shouldn’t be any outages due to vegetation from blowing into the conductors. There active ROW should be wide enough to prevent these types of outages.
Duke Energy	Disagree	This requirement needs to be re-written such that it is a performance-based requirement with graduated VSLs. As currently written, this requirement is a binary requirement which carries a single VSL which can only be “Severe”. This may drive overly-aggressive and costly vegetation management programs that carry minimal additional reliability benefit. A performance-based requirement should be developed relative to some metric such as line-mile exposure that will promote high quality vegetation management, optimization of the reliability cost/benefit relationship and deliver the overall end result of improved reliability to the system. The performance-based requirement may still be zero tolerance, but should be structured for a graduated VSL.
ISO/RTO Council		The SRC has no comment on this question.

8. As stated in the background information above, in response to industry comments, the Requirement for preventing Sustained Outages due to fall-ins of vegetation (the new R8) is developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Organization	Yes or No	Question 8 Comment
Entegra Power Group LLC		No comment
Ameren	Agree	
American Electric Power	Agree	
Associated Electric Cooperative, Inc.	Agree	
Bonneville Power Administration	Agree	
Consolidated Edison Company of New York Inc.	Agree	
Entergy Services, Inc	Agree	
Georgia Transmission Corporation	Agree	
Hydro One Networks inc.	Agree	
Hydro-Quebec TransEnergie (HQT)	Agree	
Idaho Power Company	Agree	
Independent Electricity System	Agree	

Organization	Yes or No	Question 8 Comment
Operator		
ISO New England Inc.	Agree	
Lee County Electric Cooperative	Agree	
Manitoba Hydro	Agree	
National Grid	Agree	
Nebraska Public Power District	Agree	
NERC Standards Review Subcommittee	Agree	
New Brunswick Power Transmission	Agree	
North Carolina Electric Membership Corporation	Agree	
Northeast Power Coordinating Council--RSC	Agree	
Northeast Utilities	Agree	
Oncor Electric Delivery	Agree	
Orange and Rockland Utilities, Inc.	Agree	
Pepco Holdings, Inc - Affiliates (PHI)	Agree	
Platte River Power Authority	Agree	

Organization	Yes or No	Question 8 Comment
Vegetation Management Group		
Progress Energy Carolinas, Inc.	Agree	
Public Service Co. of New Mexico	Agree	
Puget Sound Energy	Agree	
ReliabilityFirst Corporation	Agree	
Salt River Project	Agree	
SCE&G	Agree	
SERC Vegetation Managment Sub-committee (VMS)	Agree	
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Tucson Electric Power Company	Agree	
TVA	Agree	
TVA	Agree	
TVA	Agree	

Organization	Yes or No	Question 8 Comment
Vegetation Management Team	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Central Maine Power an Energy East Company	Agree	Active right of way is an important component to R8.
Northern Indiana Public Service Company	Agree	Have concerns about T.O.'s determining what is "active" and "inactive" R.O.W. which are explained in Question 1 comments.
Southern California Edison Company	Agree	SCE agrees with the content of the new R8, but believes that R8 should be combined with the new R7 into a single requirement (a revised new R7). It appears to SCE that both bulleted exceptions listed in new R8 can be applied to a revised new R7 which would then read: NEW R7. Each Transmission Owner shall prevent Sustained Outages of applicable lines due to the blowing together of vegetation and a conductor, or, vegetation falling into a conductor from within an Active Transmission Line Right of Way, with the following exceptions: [Violation Risk Factor - Medium] [Time Horizon - Real Time]o Sustained Outages of applicable lines that result from natural disasters or wind-blown debris.o Sustained Outages of applicable lines that result from human or animal activity.
Tampa Electric Company	Agree	The white paper again states that the conductor is operating within its normal rating. If, when it is operating above its normal rating it is not classified as a vegetation related outage under the Standard, this needs to be clarified in the standard itself.
Arizona Public Service	Disagree	APS understand the concept of active ROW but the SDT needs to clarify trees within the easement or permitted ROW and those outside the ROW. Utilities have a responsibility to maintain those within and shall be held accountable.
American Transmission Company	Disagree	ATC requests the SDT to clarify whether this includes branches partially severed from the tree falling into a conductor from within the active ROW.
FirstEnergy Corp	Disagree	FE suggests a removal of R8. See our response to Question 5 for further information.

Organization	Yes or No	Question 8 Comment
BC Transmission Corporation	Disagree	I strongly recommend that this be changed from “shall prevent sustained outages” to “shall minimize sustained outages due to fall ins. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. This could lead to an incident where utilities are charged unreasonably - for example, for an outage from a tree that was one foot within the active ROW line. We should not be held liable when reasonable due diligence is practiced. Further, it is not economically feasible for utilities to survey every ROW in the U.S. and Canada to determine precise clearance zones.
US Bureau of Reclamation	Disagree	It is not clear why Natural disasters or human or animal activity or wind blown debris have to do with vegetation fall-ins and why they would need to be exempted.
PacifiCorp	Disagree	PacifiCorp suggests inserting “by a qualified observer” after “observed.” Otherwise, utilities could be held accountable to train all their workers who might casually encounter vegetation conditions in their work or commutes.
Pacific Gas and Electric Co.	Disagree	PG&E agrees in principal with R5 but disagrees with the exception for human activity noted in footnote (5), specifically aboriculture, horticulture or agricultural activities. This exception is overly broad and could be interpreted as exempting certian activities (such as planting orchards) from the standard and will invite legal challenges to the TO’s right to perform vegetation management. PG&E proposes alternative language to the exception as follows: Examples include, but are not limited to, logging, animal severing tree, vehicle contact with tree, digging or removal of tree or new plantings between inspection cycles where the TO does not have actual knowledge. As an alternative, add a generic force majeure statement as described in Q18 #2.
Xcel Energy	Disagree	Please see our comments above concerning footnotes 4 & 5.
JEA	Disagree	Please see the comment to question 4.
CenterPoint Energy	Disagree	R8 refers to “Active Transmission Line Right of Way” which is not defined as to its limits within the Standard. The SDT has indicated in its response to 1st Draft Comments from CenterPoint Energy that the “...Transmission Owner is responsible for defining the Active Transmission Line Right of Way.” However, that defining clause is not included in the current definition. CenterPoint Energy recommends deleting the phrase, “within an Active Transmission Line Right of Way”, and revising R8 to read, “Each Transmission Owner shall prevent Sustained Outages of applicable lines due to vegetation falling into a conductor where the Transmission Owner had the legal right or prior permission to remove the vegetation.”Since R1 in the Standard does not address how a Transmission Owner conducts its work to address the fall-in of trees into an adjacent transmission line, R8 may not be needed in the Standard. In the Technical Reference under the Applicability of the Standard, the SDT states that “On the other hand, most other outage causes (such as

Organization	Yes or No	Question 8 Comment
		trees falling into lines....) are statistically intermittent. The probability of occurrence of these events is not dependent on heavy loads. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures." This observation made by the SDT would support the removal of R8 from the Standard. R8 appears to be a major driving cause for introducing the new term "Active Transmission Line Right of Way", and removing R8 would avoid the need to introduce this ambiguously defined term and simplify the Standard without significant impact on its intended purpose. The impact of R8 is also diminished by the fact that the majority of fall-ins occur as a result of the exceptions currently stated in the rule and are typically from outside the maintained boundary of the right of way.
E.ON U.S.	Disagree	The standard must be consistent with R4
Transmission Owner	Disagree	This requirement is not congruent with the purpose of this standard. The standard was enacted as a result of the North East Blackout and a history of grid blackouts in which the growth of trees below conductors under load contributed to the situation. Trees falling into the conductor create no more risk to cascading than causes such as lightning or foreign interference. This requirement should be removed from the standard.
Duke Energy	Disagree	This requirement needs to be re-written such that it is a performance-based requirement with graduated VSLs. As currently written, this requirement is a binary requirement which carries a single VSL which can only be "Severe". This may drive overly-aggressive and costly vegetation management programs that carry minimal additional reliability benefit. A performance-based requirement should be developed relative to some metric such as line-mile exposure that will promote high quality vegetation management, optimization of the reliability cost/benefit relationship and deliver the overall end result of improved reliability to the system. The performance-based requirement may still be zero tolerance, but should be structured for a graduated VSL.
ISO/RTO Council		The SRC has no comment on this question.

9. As stated in the background information above, in response to industry comments, the Requirement for implementation of annual work plan (the new R9) is developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Organization	Yes or No	Question 9 Comment
Entegra Power Group LLC		No comment
Ameren	Agree	
American Electric Power	Agree	
Associated Electric Cooperative, Inc.	Agree	
BC Transmission Corporation	Agree	
Bonneville Power Administration	Agree	
CenterPoint Energy	Agree	
Consolidated Edison Company of New York Inc.	Agree	
Duke Energy	Agree	
E.ON U.S.	Agree	
Entergy Services, Inc	Agree	
Georgia Transmission Corporation	Agree	

Organization	Yes or No	Question 9 Comment
Hydro One Networks inc.	Agree	
Hydro-Quebec TransEnergie (HQT)	Agree	
Independent Electricity System Operator	Agree	
ISO New England Inc.	Agree	
JEA	Agree	
Lee County Electric Cooperative	Agree	
National Grid	Agree	
NERC Standards Review Subcommittee	Agree	
New Brunswick Power Transmission	Agree	
North Carolina Electric Membership Corporation	Agree	
Northeast Power Coordinating Council--RSC	Agree	
Northeast Utilities	Agree	
Northern Indiana Public Service Company	Agree	
Orange and Rockland Utilities,	Agree	

Organization	Yes or No	Question 9 Comment
Inc.		
Pacific Gas and Electric Co.	Agree	
Pepco Holdings, Inc - Affiliates (PHI)	Agree	
Progress Energy Carolinas, Inc.	Agree	
Public Service Co. of New Mexico	Agree	
Puget Sound Energy	Agree	
ReliabilityFirst Corporation	Agree	
SCE&G	Agree	
SERC Vegetation Managment Sub-committee (VMS)	Agree	
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tampa Electric Company	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Transmission Owner	Agree	
Tucson Electric Power Company	Agree	

Organization	Yes or No	Question 9 Comment
TVA	Agree	
TVA	Agree	
TVA	Agree	
US Bureau of Reclamation	Agree	
Vegetation Management Team	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Southern California Edison Company	Agree	SCE agrees with the content of the new R9, however, we suggest it be placed immediately after R1 and be identified as the new R2. SCE suggests that the requirement be modified to read: R9(R2). Each Transmission Owner shall implement its annual work plan for VegetationManagement.
Oncor Electric Delivery	Disagree	Comments: See response to Q.1 The VSL for R9 indicate “failure to implement” percentages of the annual work plan for the different VSL levels. There is lack of clarity in how “percentage” is defined. Is percentage based on 1) # of lines in the annual plan vs # lines not worked according to the annual plan or 2) miles of line not implemented vs total miles in the annual plan?
Platte River Power Authority Vegetation Management Group	Disagree	It seems apparent that if you have a work plan (R1.3.) you should implement that plan and M9 specifies the evidence of such implementation is specific to the work plan. However, the requirement is ambiguous as we interpret it to apply only to the work plan as outlined in R1.3. but the last sentence "...to accomplish the purpose of this standard" makes us wonder if perhaps the implementation and documentation required is boarder. We understand that the implementation of the work plan is separated into a separate requirement so that different VRF and VSL can be assigned but it would provide more clarity if the requirement were as follows: R9. Each Transmission Owner shall implement and document its annual work plan for vegetation management to meet R1.3. In cases when the annual work plan is adjusted or not completely implemented as originally planned, the reasons for the deferrals or changes and the expected completion date of the postponed work should be documented as well.

Organization	Yes or No	Question 9 Comment
Nebraska Public Power District	Disagree	NPPD agrees with the wording provided by Xcel Energy. Each Transmission Owner shall implement its annual work plan for vegetation management to accomplish the purpose of this standard, subject to its legal rights.
Central Maine Power an Energy East Company	Disagree	Restore the phrase " within the extent of its easement and/or legal rights" found in FAC 003 1 .
Idaho Power Company	Disagree	Reword R9 to say 'The TO shall implement its annual work plan for vegetation management within its legal rights...'
American Transmission Company	Disagree	Same response as in Question # 1 (addressing R1.3 and R1. 5) ATC believes that Requirement 9 should allow for flexibility in the annual work plan to carry over implementation to the following calendar year.
Manitoba Hydro	Disagree	The annual work plan should allow for justification to carry over the implementation to the following calendar year or years.
PacifiCorp	Disagree	The current language of the requirement places the sole burden for implementation of the annual work plan, including the correction timeframe, on the Transmission Owner. This could be problematic on federal property where local district offices have authority over whether or not to approve vegetation management work. In order to implement their annual work plans, Transmission Owners must obtain approval from any applicable federal agency through that agency's approval process. There are occasions where authorization from that agency may take many months or even years. The language of the requirement should be modified to take this into account; if authorization from the applicable federal agency is not granted within six months, the Transmission Owner should not be subject to penalties or sanctions because these would be associated with actions beyond their control.
Arizona Public Service	Disagree	There should be a footnote that if federal or state agencies fail to approve annual work plans within 90 days of submittal the utility will not be held accountable for not completing its annual work plan or taking into account the time it takes to get approval. We have land agencies that give us approvals within 2 weeks and others that have taken over a year. Utilities are at their mercy on the approval process. If there is turn-over in the land agency the approval process changes again and it is impossible to determine the anticipated timeline by state, tribal and federal agencies.
Salt River Project	Disagree	There should be an additional statement to include "subject to the Transmission Owner's legal rights". This requirement should acknowledge the difficulties Transmission Owner's have working with federal and state

Organization	Yes or No	Question 9 Comment
		agencies that do not approve work plans in a timely manner.
FirstEnergy Corp	Disagree	We agree with this requirement except for the phrase "to accomplish the purpose of this standard". This phrase is unnecessary and could lead to unintended interpretations. It is understood that every requirement in each reliability standard is written to accomplish the purpose of its respective standard, and those words should not be required in the text of the requirements.
Xcel Energy	Disagree	Xcel Energy strongly believes that the requirement that each Transmission Owner shall implement its annual work plan for vegetation management must acknowledge that such vegetation management is subject to the legal rights available to the Transmission Owner. Hence, it is suggested that R9 be revised to read: "Each Transmission Owner shall implement its annual work plan for vegetation management to accomplish the purpose of this standard, subject to its legal rights."
ISO/RTO Council		The SRC has no comment on this question.

10. As stated in the background information above, in response to industry comments, the Requirement for the preparation of list for sub 200kV transmission lines by the Planning Coordinator (the new R10) is developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Organization	Yes or No	Question 10 Comment
Entegra Power Group LLC		No comment
Tampa Electric Company		We do not agree or disagree on this Requirement.
Ameren	Agree	
American Electric Power	Agree	
Arizona Public Service	Agree	
Associated Electric Cooperative, Inc.	Agree	
BC Transmission Corporation	Agree	
Bonneville Power Administration	Agree	
CenterPoint Energy	Agree	
Central Maine Power an Energy East Company	Agree	
Consolidated Edison Company of New York Inc.	Agree	
Duke Energy	Agree	

Organization	Yes or No	Question 10 Comment
E.ON U.S.	Agree	
Entergy Services, Inc	Agree	
Georgia Transmission Corporation	Agree	
Hydro One Networks inc.	Agree	
Idaho Power Company	Agree	
JEA	Agree	
Lee County Electric Cooperative	Agree	
Manitoba Hydro	Agree	
National Grid	Agree	
Nebraska Public Power District	Agree	
New Brunswick Power Transmission	Agree	
North Carolina Electric Membership Corporation	Agree	
Northeast Utilities	Agree	
Northern Indiana Public Service Company	Agree	
Oncor Electric Delivery	Agree	

Organization	Yes or No	Question 10 Comment
Orange and Rockland Utilities, Inc.	Agree	
Pacific Gas and Electric Co.	Agree	
PacifiCorp	Agree	
Pepco Holdings, Inc - Affiliates (PHI)	Agree	
Progress Energy Carolinas, Inc.	Agree	
Puget Sound Energy	Agree	
ReliabilityFirst Corporation	Agree	
Salt River Project	Agree	
SCE&G	Agree	
SERC Vegetation Managment Sub-committee (VMS)	Agree	
Southern Company	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Transmission Owner	Agree	
Tucson Electric Power Company	Agree	
TVA	Agree	

Organization	Yes or No	Question 10 Comment
TVA	Agree	
TVA	Agree	
Vegetation Management Team	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Xcel Energy	Agree	
Superintendent Transmission Maintenance	Agree	Agree with the requirements under R10, however, request further clarification on the source and qualifications of the "Planning Coordinator".
Edison Electric Institute	Agree	First, EEI generally agrees with the draft revised applicability section. In addition and to help reduce ambiguity in the text, EEI asks that the SDT consider additional language in R.10 and R. 11 (and M. 10 and M. 11) that Planning Coordinators be required to include all facilities under 200 kv identified as IROL facilities under FAC-014. For example, the language of the applicability of the Standard could be stated to include all facilities under 200 kv identified under FAC-014 as IROL facilities. The corresponding requirement could be stated as ‘Each Planning Coordinator will notify all Registered Entities under 200 kv for which this Reliability Standard applies.’ EEI also believes that this change would be consistent with the discussion of the issue in Order No. 693 (P. 706)Second, EEI recommends consideration for including in the applicability section of the Standard the phrase from the technical paper, i.e., the Standard will not apply to line sections inside the electric station fence or other boundary of an electric station, or underground lines. (Technical Paper, p. 8) If included, this addition would add much-needed clarity for Registered Entities.In particular, EEI encourages further consideration for lines from generation facilities to network substations. Some Generation Owners have lines greater than a mile in length EEI asks the SDT consider whether to extend applicability of the Standard for Generation Owners that own lines that meeting certain predefined criteria, or other approaches that would clarify the treatment of lines owned by Generation Owners on the generator side of a network substation. Finally, further clarification may be needed on whether the Standard will cover all facilities rated at greater than 200 kv. For example, there may be 230 kv radial lines to distribution deemed exempt from a BPS -defined set of assets. EEI understands that some confusion exists on whether the threshold BPS

Organization	Yes or No	Question 10 Comment
		definition governs applicability for all individual Standards.
Southern California Edison Company	Agree	SCE generally agrees with the requirement, but is concerned about the new role for the Planning Coordinator and the posibility that it will have shared compliance responsibilities for designated lines with the Transmission Owner.
Hydro-Quebec TransEnergie (HQT)	Disagree	NERC standards apply only to BES facilities and not necessarily at voltage level threshold. The standards should not apply to facilities that are not BES. Within a standard there might be exceptions for cases where the standard would apply only to a subset of the BES facilities. The only change between the current standard and the proposed draft is who designates critical lines. In the current standard it was the RRO while in the new standard it is the PC. The RRO (or the PC in the future version) can only designate critical lines among those that are already classified as BES.Furthermore, the purpose of the standard should be changed to read : 'To improve the reliability of the Bulk Electric System by preventing....' since the NERC Standards are designed to be applicable to the BES, not the 'electric transmission system'; or is it the real intention of NERC to have some standards for BES and some for 'electric transmission system'? We would appreciate to have the SDT opinion on this.
Independent Electricity System Operator	Disagree	NERC standards apply only to BES facilities, and not necessarily a voltage level threshold. The standards should not apply to facilities that are not BES. Within a standard there might be exceptions for cases where the standard would apply only to a subset of the BES facilities. This is the case of the FAC-003 current standard and the new draft which both state that the standard applies only to transmission lines operated at 200 kV and above, and to any lower voltage lines designated as critical to the reliability of the electric system in the region. The only change between the current standard and the proposed draft is who designates the above critical lines. In the current standard it was the RRO while in the new standard it is the PC. The RRO (or the PC in the future version) can only designate critical lines among those that are already classified as BES.
Northeast Power Coordinating Council--RSC	Disagree	NERC standards apply only to BES facilities, and not necessarily a voltage level threshold. The standards should not apply to facilities that are not BES. Within a standard there might be exceptions for cases where the standard would apply only to a subset of the BES facilities. This is the case of the FAC-003 current standard and the new draft which both state that the standard applies only to transmission lines operated at 200 kV and above, and to any lower voltage lines designated as critical to the reliability of the electric system in the region. The only change between the current standard and the proposed draft is who designates the above critical lines. In the current standard it was the RRO while in the new standard it is the PC. The RRO (or the PC in the future version) can only designate critical lines among those that are already classified as BES.

Organization	Yes or No	Question 10 Comment
ISO New England Inc.	Disagree	NERC standards apply only to BES facilities. The standards should not apply to facilities that are not BES. Within a standard there might be exceptions for cases where the standard would apply only to a subset of the BES facilities. This is the case of the FAC-003 current standard and the new draft which both state that the standard applies only to transmission lines operated at 200 kV and above, and to any lower voltage lines designated as critical to the reliability of the electric system in the region. The only change between the current standard and the proposed draft is who designates the above critical lines. In the current standard it was the RRO while in the new standard it is the PC. The RRO (or the PC in the future version) can only designate critical lines among those that are already classified as BES.
Public Service Co. of New Mexico	Disagree	PNM disagrees with the use of the "Planning Coordinator." There is no definition of this individual or group of individuals anywhere in the proposed standard or white paper that is apparent. Clarification is needed.
MRO NERC Standards Review Subcommittee	Disagree	R10 states that the PC “consult” with its TOs and neighboring PCs to obtain input for the list of qualifying facilities operated below 200 kV. What does “consult” mean? It is a surrogate for “coordinate” which is being removed from standards because of compliance implications - an entity might be held in violation if another entity did not respond or act to “coordinate” the effort. Also, R11 uses the terms “reliability significance” and “unacceptable risk of instability” which are undefined and not measurable. R11 is the lead requirement and could be moved to new R1 location. Better wording would be “Each PC must develop and document a methodology for determining a list of facilities in its area operated at less than 200 kV whose loss would cause instability, separation or cascading failures on the BES. “ R10 follows directly and would become new R2. Better wording would be “Each PC shall prepare and review annually a list of facilities in its area operated at less than 200 kV which are subject to this standard. This list will be based on information obtained from its TOs. Results will be provided to its TOs and neighboring PCs.”
American Transmission Company	Disagree	See response to Question #11 below.
Platte River Power Authority Vegetation Management Group	Disagree	The requirement is confusing as it infers that it relates to R11 but never states such. It might be clearer if it followed R11, as we believe the correct process should be as stated in the FAC-003-2 Technical Reference: "Planning Coordinators, using their methodologies described in R11, will need to conduct the necessary studies and identify candidate sub-200kV transmission lines for potential applicability under the Standard. The Planning Coordinators will next need to consult with its Transmission Owners and neighboring Planning Coordinators to resolve any differences in the selection of the sub-200kV transmission lines of common interest. Finally, the Planning Coordinator will need to finalize, adopt and issue the list of designated sub-200kV lines". The way it is currently written the Planning Coordinator will need to finalize, adopt and issue the list of designated sub-200kV lines first then consult with its Transmission Operators and neighboring Planning

Organization	Yes or No	Question 10 Comment
		Coordinators and last develop a methodology. We aren't sure why R10 and R11 are separate requirements as they seem to be related and both have the same VRF and time horizon. We believe the two requirements should be combined and placed in sequential order.
US Bureau of Reclamation	Disagree	The role of the Planning Coordinator is inappropriately described in this requirement. The role of the Planning Coordinator as related in the NERC Functional Model is to conduct assessments of transmisssion systems. Planning Coordinators do not implement resource plans (NERC Functional Model Technical Document Page 12 last paragraph). The determination of criticality is an implementation action or operational determination which is reserved for either the Transmission Planner or the Reliability Coordinator. The role of the Planning coordinator is to develop methodologies which are used by others in ensuring reliable BES operation. Specifically the "Planning Coordinator coordinates and evaluates and recommends reinforcement and corrective plans resulting from studies and analysis of system performance and interconnection of facilities." To require the Planning Coordinator to prepare a list of lines which are subject to this standard (critical to the BES) is modifying the role of the Planning Coordinator and should be examined in the context of the role of the Transmission Operator, Transmission Owner, Transmission Planner and Reliability Cooridnator under a separate project.
FirstEnergy Corp	Disagree	We suggest the team consider changes to R10 and R11 to ensure consistency with standard FAC-014 for the transmission facilities that are sub-200kV and deemed as having "reliability significance" and placing the grid at risk for instability and Cascading. FE believes the appropriate set of sub-200kV lines are those identified as being associated with an IROL condition. Utilizing an already established IROL methodology (FAC-010 and FAC-014) eliminates the need for the Planning Coordinator to coordinate with the Transmission Owner(s) alleviating a level of tedious compliance evidence for the Planning Coordinator. Finally, presently missing within the requirement is the need for the Planning Coordinator to submit a list of the reliability significant sub-200kV facilities to the Transmission Owner(s).We propose that requirements R10 and R11 be replace with a single new R10 requirement as follows:"R10 Each Planning Coordinator shall prepare and review annually, a list of lines thatare operated below 200kV, if any, which are subject to this standard. 10.1 The list shall reflect sub-200kV transmission facilities associated with an IROL condition as identified per NERC reliability standard FAC-014. 10.2 The Planning Coordinator shall annually notify its Transmission Owner(s) of the sub-200kV reliability significant facilities that are subject to this standard."No changes to the Violation Risk Factors or Time Horizons for the proposed requirement. We support a VRF of Lower and Time-Horizon of Long-Term Planning.If the proposal is accepted, conforming changes to the Measures are required.Lastly, the team should consider asking NERC to add to its Standards Development issues database a need to revise standard FAC-014 such that the Transmission Owner is notified of all IROL transmission facilities as part of FAC-014. This would allow for changes in FAC-003 that could eliminate the Planning Coordinator as being applicable to the FAC-003 standard.

Organization	Yes or No	Question 10 Comment
ISO/RTO Council	Disagree	We reiterate our comments submitted for Version 1 that the Planning Coordinators and Reliability Coordinators do not have a role in this standard, and requirements R10 and R11 are not needed. Facilities below 200KV are generally not critical on a wide area basis. There may be some facilities that are critical for local service – most likely in metropolitan areas or a very rural system where they are wholly dependent on sub 200KV facilities. Therefore, there is not a need for a wide area assessment by the Planning Coordinator in this standard. Those facilities below 200KV that are vital for local service would already be identified and included in the vegetation management program of the Transmission Owner. Further, facilities that are associated with IROLs, regardless of voltage class, are already identified through the R5 requirements. We understand the SDT's response to our initial comments that FERC expects this standard to require the identification of relevant sub 200KV facilities, but for the reasons presented in these comments, we believe that sub 200KV facilities relevant to wide area reliability are few and there should not be an expectation or requirement for the PCs to identify significant portions of sub 200kv facilities for purposes of this standard. Such facilities should be included only when the PC has documented a need.

11. As stated in the background information above, in response to industry comments, the Requirement for the Planning Coordinator to document method for identification of applicable sub-200kV transmission lines (the new R11) is developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Organization	Yes or No	Question 11 Comment
Entegra Power Group LLC		No comment
Tampa Electric Company		We do not agree or disagree on this Requirement.
Ameren	Agree	
American Electric Power	Agree	
Arizona Public Service	Agree	
Associated Electric Cooperative, Inc.	Agree	
BC Transmission Corporation	Agree	
Bonneville Power Administration	Agree	
CenterPoint Energy	Agree	
Central Maine Power an Energy East Company	Agree	
Consolidated Edison Company of New York Inc.	Agree	
Duke Energy	Agree	

Organization	Yes or No	Question 11 Comment
E.ON U.S.	Agree	
Entergy Services, Inc	Agree	
Georgia Transmission Corporation	Agree	
Hydro One Networks inc.	Agree	
Idaho Power Company	Agree	
Lee County Electric Cooperative	Agree	
Manitoba Hydro	Agree	
National Grid	Agree	
Nebraska Public Power District	Agree	
New Brunswick Power Transmission	Agree	
North Carolina Electric Membership Corporation	Agree	
Northeast Utilities	Agree	
Northern Indiana Public Service Company	Agree	
Oncor Electric Delivery	Agree	
Orange and Rockland Utilities, Inc.	Agree	

Organization	Yes or No	Question 11 Comment
Pacific Gas and Electric Co.	Agree	
PacifiCorp	Agree	
Pepco Holdings, Inc - Affiliates (PHI)	Agree	
Progress Energy Carolinas, Inc.	Agree	
ReliabilityFirst Corporation	Agree	
Salt River Project	Agree	
SCE&G	Agree	
SERC Vegetation Managment Sub-committee (VMS)	Agree	
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Transmission Owner	Agree	
Tucson Electric Power Company	Agree	
TVA	Agree	
TVA	Agree	

Organization	Yes or No	Question 11 Comment
TVA	Agree	
US Bureau of Reclamation	Agree	
Vegetation Management Team	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Puget Sound Energy	Agree	Assuming the Planning Coordinator is approved through the functional model revisions and entities register for it.
JEA	Agree	Might want to consider adding something along the lines of "for the purposes of vegetation management" at the end to clarify the purpose of the list.
Southern California Edison Company	Agree	SCE generally agrres with the requirement, but is concerned about the role identified for the Planning Coordinator and the possibility that it will have shared compliance responsbilities with the Transmission Owner for certain identified lines.
Public Service Co. of New Mexico	Disagree	Again, see comment from Question 12 - no definition of the term "Planning Coordinator."
American Transmission Company	Disagree	ATC proposes the following:Remove both R10 and R11 because the TPL-002 and TPL-003 standards already require the Transmission Planner and the Planning Coordinator to ensure reliable system operation for loss of single-element and multi-element contingencies. ATC recommends changing the appropriate text in the first two items under A4.2, Facilities: to “. . . transmission lines operated below 200kv that are identified as an element of an IROL or Major WECC Transfer Path”.In addition, TPL-002 and TPL-003 require the TP and PC to identify IROL’s so that the applicability section of this document should use the outcome from those approved Reliability Standards as an input for this standard. Structuring the standard in this way will makes future enhancement efforts more efficient.If the R10 and R11 removal suggestion is rejected, then revise R11 to, “. . . its methodology for assessing which, if any, lines are subject to this standard. The methodology shall describe the process for determining which lines, if any, below 200kV are expected to have an unacceptable

Organization	Yes or No	Question 11 Comment
		instability or cascading outcome due to TPL-002 and TPL-003 conditions.”
NERC Standards Review Subcommittee	Disagree	See comments above in Question 10.
Platte River Power Authority Vegetation Management Group	Disagree	The criteria for assessing the lines whose loss would place the gird at an unacceptable risk of instability, separation, or cascading failures needs to be more clearly defined. We interpret R10 and R11 to mean that any Category B contingency of a sub-200kV line that causes instability, separation, or cascading failure is subject to FAC-003-2. Is this your desired level of assessment?
Hydro-Quebec TransEnergie (HQT)	Disagree	This should apply to all BES transmission facilities. The use of 200kV as a threshold should be removed. See also Q10 answer.
Independent Electricity System Operator	Disagree	This should apply to all BES transmission facilities. The use of 200kV as a threshold should be removed.
ISO New England Inc.	Disagree	This should apply to all BES transmission facilities. The use of 200kV as a threshold should be removed.
Northeast Power Coordinating Council--RSC	Disagree	This should apply to all BES transmission facilities. The use of 200kV as a threshold should be removed.
FirstEnergy Corp	Disagree	We propose the removal of requirement R11. See our response to Question 10 for further details.
ISO/RTO Council		The SRC has no comment on this question.

12. The SDT received suggestions from commenters to re-sequence the requirements contained in the standard to improve the logical flow of this document. The SDT submits for consideration a proposed alternative sequence. Do you agree with the proposed alternative sequencing? If not, please recommend a suggested sequence.

Organization	Yes or No	Question 12 Comment
Entegra Power Group LLC		No comment
Pepco Holdings, Inc - Affiliates (PHI)		No preference. All standards must be considered in entirety for compliance.
Ameren	Agree	
American Electric Power	Agree	
Arizona Public Service	Agree	
BC Transmission Corporation	Agree	
Bonneville Power Administration	Agree	
CenterPoint Energy	Agree	
Consolidated Edison Company of New York Inc.	Agree	
Duke Energy	Agree	
E.ON U.S.	Agree	
Entergy Services, Inc	Agree	
Georgia Transmission	Agree	

Organization	Yes or No	Question 12 Comment
Corporation		
Hydro One Networks inc.	Agree	
Idaho Power Company	Agree	
Independent Electricity System Operator	Agree	
ISO New England Inc.	Agree	
Lee County Electric Cooperative	Agree	
Manitoba Hydro	Agree	
National Grid	Agree	
Nebraska Public Power District	Agree	
North Carolina Electric Membership Corporation	Agree	
Northeast Power Coordinating Council--RSC	Agree	
Northeast Utilities	Agree	
Oncor Electric Delivery	Agree	
Orange and Rockland Utilities, Inc.	Agree	
Pacific Gas and Electric Co.	Agree	
PacifiCorp	Agree	

Organization	Yes or No	Question 12 Comment
Platte River Power Authority Vegetation Management Group	Agree	
Progress Energy Carolinas, Inc.	Agree	
Public Service Co. of New Mexico	Agree	
Puget Sound Energy	Agree	
Salt River Project	Agree	
SCE&G	Agree	
SERC Vegetation Managment Sub-committee (VMS)	Agree	
Southern California Edison Company	Agree	
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tampa Electric Company	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Transmission Owner	Agree	
Tucson Electric Power Company	Agree	

Organization	Yes or No	Question 12 Comment
TVA	Agree	
TVA	Agree	
TVA	Agree	
US Bureau of Reclamation	Agree	
Vegetation Management Team	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Xcel Energy	Agree	
Hydro-Quebec TransEnergie (HQT)	Agree	As per our answer to Q5, R5 and R6 should be combined to R5 with the elimination of the IROL concept.
American Transmission Company	Agree	ATC agrees generally with the rearrangement. We believe that the proposed requirements R11 and R10 should be removed because can be adequately covered in the applicability section of this document. The remaining proposed reorder would then be okay.
MRO NERC Standards Review Subcommittee	Agree	N/A
ReliabilityFirst Corporation	Agree	This proposed sequence flows better. Feel that R10 and R11 can be combined into one.
JEA	Agree	Would not the Vegetation Inspections be documented in the Work Plan? Perhaps those two should be switched or combined. I'd move Implement Imminent Threat to the end.
Associated Electric Cooperative,	Disagree	Associated Electric Cooperative Inc. believes the current requirements sequence is appropriate.

Organization	Yes or No	Question 12 Comment
Inc.		
Northern Indiana Public Service Company	Disagree	Prefer current sequence except I have no objection to placing the PC requirements at the top of the list.
New Brunswick Power Transmission	Disagree	Propose further revision of "alternate sequence" to R1-4, R6, R5, R7, R10, R11, R9, R8. Suggested proposal reflects dealing with high priority issues first. That is imminent threats must be handled before planned work. Similarly for prevention of outages grow-ins are the most critical, followed by blow-ins and fall-ins.
Central Maine Power an Energy East Company	Disagree	Suggest reverse R4 with R5.
FirstEnergy Corp	Disagree	While we don't have a strong opinion on this, we believe the proposed sequence of R8, R9, R10 and R11 (old R8, R7, R6 and R5) would be better placed in the following order using the teams designated proposed numbering: R11, R10, R8 and R9. This order is suggested so that a greater emphasis on grow-in and IROL is accomplished and that the standard addresses those items first.
ISO/RTO Council		The SRC has no comment on this question.

13. The Implementation Plan proposes an effective date that gives entities at least a year to become fully compliant. Do you agree with this implementation plan? If not, please indicate what should be changed and indicate why.

Organization	Yes or No	Question 13 Comment
Ameren	Agree	
American Transmission Company	Agree	
Arizona Public Service	Agree	
Associated Electric Cooperative, Inc.	Agree	
BC Transmission Corporation	Agree	
Bonneville Power Administration	Agree	
CenterPoint Energy	Agree	
Central Maine Power an Energy East Company	Agree	
Consolidated Edison Company of New York Inc.	Agree	
Duke Energy	Agree	
E.ON U.S.	Agree	
Entegra Power Group LLC	Agree	

Organization	Yes or No	Question 13 Comment
FirstEnergy Corp	Agree	
Georgia Transmission Corporation	Agree	
Hydro One Networks inc.	Agree	
Hydro-Quebec TransEnergie (HQT)	Agree	
Idaho Power Company	Agree	
Independent Electricity System Operator	Agree	
ISO New England Inc.	Agree	
JEA	Agree	
Lee County Electric Cooperative	Agree	
Manitoba Hydro	Agree	
National Grid	Agree	
Nebraska Public Power District	Agree	
New Brunswick Power Transmission	Agree	
North Carolina Electric Membership Corporation	Agree	
Northeast Power Coordinating	Agree	

Organization	Yes or No	Question 13 Comment
Council--RSC		
Northeast Utilities	Agree	
Northern Indiana Public Service Company	Agree	
Oncor Electric Delivery	Agree	
Orange and Rockland Utilities, Inc.	Agree	
Pacific Gas and Electric Co.	Agree	
PacifiCorp	Agree	
Pepco Holdings, Inc - Affiliates (PHI)	Agree	
Platte River Power Authority Vegetation Management Group	Agree	
Progress Energy Carolinas, Inc.	Agree	
Public Service Co. of New Mexico	Agree	
Puget Sound Energy	Agree	
ReliabilityFirst Corporation	Agree	
Salt River Project	Agree	
Southern California Edison Company	Agree	

Organization	Yes or No	Question 13 Comment
Superintendent Transmission Maintenance	Agree	
Tampa Electric Company	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Transmission Owner	Agree	
Tucson Electric Power Company	Agree	
TVA	Agree	
TVA	Agree	
TVA	Agree	
US Bureau of Reclamation	Agree	
Vegetation Management Team	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Xcel Energy	Agree	
American Electric Power	Agree	The one year should be adequate presuming that the Planning Coordinator does not designate significant numbers of facilities below 200 kV. Should this become the case, a year would be insufficient to for implementation.

Organization	Yes or No	Question 13 Comment
MRO NERC Standards Review Subcommittee	Disagree	MRO NSRS does not believe that current proposed implementation time in Facilities 4.2.2 is adequate. Given the time required to conduct a survey to determine if a company's lines are maintained sufficiently to meet the new requirements, in addition to the time and resources (both budgetary and labor) required to implement the results of the survey, we believe that between 24 and 36 months may be required to implement this version of the standard.
SCE&G	Disagree	SCE&G believes that this standard is superior to the existing standard and therefore requests that the effective date be moved up. We also recommend that the new standard be started on a calendar year.
Southern Company	Disagree	SDT should consider a more rapid implementation plan because the new standard has significant improvement over the existing standard. For example, Southern Company feels it could be implemented the first calendar day of the first calendar quarter following approval by the NERC Board of Trustees.
SERC Vegetation Managment Sub-committee (VMS)	Disagree	The VMS believes that this standard is superior to the existing standard and therefore requests that the effective date be moved up. The VMS also recommends that the new standard be started on a calendar year.
Entergy Services, Inc	Disagree	This Standard should move forward prior to the current one year provided, it is far superior to the existing Standard.
ISO/RTO Council	Agree	If this standard retains the need to identify sub 200KV facilities, then one year provides sufficient time for Planning Coordinators to meet R10 and R11.

14. Do you have further questions about the standard that the Technical Reference document (White Paper) does not clear up? If so, please elaborate and propose additions.

Organization	Yes or No	Question 14 Comment
Xcel Energy		(a) To avoid confusion, the diagrams of the ROWs in the White Paper should not have tree-like objects in the Active Transmission Right of Way. If any vegetation is to be shown in those areas, the vegetation should be shrubbery.(b) The discussion on p. 24 indicates that the MVCD is the “spark-over zone.” The MVCD (hopefully to be renamed) should not directly correlate to the spark-over zone. The spark-over zone should be less than the MVCD.
Hydro One Networks inc.		(a) we suggest an illustration of R7 be added. R7 text states “... due to the blowing together of vegetation and a conductor within an Active Transmission Line ROW.” These words could suggest that sustained outages from vegetation (branches) extending within the active ROW, but originating from trees located outside the active ROW, might not be considered a preventable outage. An illustration in the reference paper would provide clarity.(b) Confusion still exists around the determination of the “active transmission line right-of-way”. The diagrams shown in the white paper, though helpful, do not necessarily apply to all field conditions. Specific questions include: Is it up to the Transmission Operator to determine the “active transmission line right-of-way”, particularly in cases where the RoW may not be maintained to the legal boundary? Example 4 in the definition of “active transmission line right-of-way” (pg. 5) uses the words “deactivated” and “unavailable for service”; these terms should be clearly defined, as there can be several degrees of de-activation and entities may interpret them differently.
BC Transmission Corporation		Active ROW needs to be defined in more detail
Arizona Public Service		Active ROW needs to defined in more detail.
Consolidated Edison Company of New York Inc.		CECONY recommends that an illustration of R7 be added to the Technical Reference document. R7 text states “ ... due to the blowing together of vegetation and a conductor within an Active Transmission Line ROW." These words could be interpreted to mean that sustained outages from vegetation (branches) extending into the active ROW, but originating from trees located outside the active ROW, might not be considered a preventable outage. An illustration in the reference paper would provide clarity.
Duke Energy		During the first comment period, it was noted that it was difficult to prove a negative. This will be the case with some of the requirements proposed in this version. For example, it would be beneficial to note in the Technical Reference Paper that documented vegetation inspections that do not identify an encroachment (R4

Organization	Yes or No	Question 14 Comment
		violation) would be proof of compliance. Other examples may exist that the team may consider including for reference.
Entegra Power Group LLC		In some way address dealing with Generator Interconnection Facilities (GIF) which only have a few spans of transmission interconnect. Will this be addressed in a future specific Standard, or as a separate requirement under FAC-003-2? Entegra suggests a much simpler approach can be employed when under 4 spans worth of vegetation can be visually inspected every 1-2 years and trimmed to prevent any possible vegetation impact to subject lines/system.
Tampa Electric Company		In the white paper, page 35, paragraph 2, it states that if the conductor is operating above its rating it "would not be classified as vegetation related sustained outage under the standard." If this is so it needs to be stated and/or clarified in the standard itself. In addition on page 35, 3rd paragraph, last sentence of the white paper it states, " Additionally, sustained outages due to wind-blown debris, such as large limbs and branches, separated tree tops, etc., are exempt from this standard." If this is so it needs to be stated in the standard. Need clarification, if the debris is from trees within the active transmission ROW is it a violation?
Tucson Electric Power Company		In the white paper, the pictorial reference of the active right of way has no reference to show what the minimum distance beyond the conductor envelope should be to establish the width of the active right of way.
US Bureau of Reclamation		It is not clear at what physical point in the BES the is standard would apply; such as from the first structure outside of the substation/switchyard or other demarcation.
National Grid		National Grid suggests an illustration of R7 be added. R7 text states " ... due to the blowing together of vegetation and a conductor within an Active Transmission Line ROW". These words could suggest that sustained outages from vegetation (branches) extending within the active ROW, but originating from trees located outside the active ROW, might not be considered a preventable outage. An illustration in the reference paper would provide clarity that these sustained outages are a violation of R7.
ReliabilityFirst Corporation		No
TVA		no
WECC RC		NO
Associated Electric Cooperative,		No comments

Organization	Yes or No	Question 14 Comment
Inc.		
North Carolina Electric Membership Corporation		None
SCE&G		None
SERC Vegetation Managment Sub-committee (VMS)		None.
Southern Company		None.
Pepco Holdings, Inc - Affiliates (PHI)		PHI has concerns that the reference document has many items that are critical to the determination of compliance.
CenterPoint Energy		Questions are listed below:1. How does the Transmission Owner determine the geometric limits of an “Active Transmission Line Right of Way” to determine how a Sustained Outage is reported under Category 1A, Category 1B, Category 2, and Category 4.2. Why does an “Inactive R.O.W.” contain trees that are within falling distance of an applicable transmission line? (Figure 1 has such a depiction.) Is the “Inactive R.O.W. outside the legal limits of the Transmission Owners’ right of way?3. Why don’t Requirements 5, 6, 7 and 8, and their corresponding Measures 5, 6, 7, and 8, and the Compliance 1.5 Sustained Outage Categories - Category 1A, Category 1B, Category 4, and Category 2 all have the same exceptions listed? For example, R5 has the exceptions for “Sustained Outages of applicable lines that result from natural disasters” and Sustained Outages of applicable lines that result from human or animal activity.” M5 and Category 1A do not contain those exceptions. Category 1A qualifies events to be reported as “inside and/or outside of the Active Transmission Line ROW”, but R5 and M5 do not have such a reference. How will the reporting differentiate between a Sustained Outage caused by improper vegetation management and those caused by natural disasters? FAC-003-1 R3.2 did not require the reporting of certain sustained transmission line outages (e.g. natural disasters, human activity, etc.). It is not clear what the current draft intends to have reported.
Nebraska Public Power District		Remove the tree-like objects from the diagrams of the ROWs in the White Paper. If any vegetation is to be shown in those areas, the vegetation should only be shrubbery.
Entergy Services, Inc		See additional Entergy comments below.

Organization	Yes or No	Question 14 Comment
Orange and Rockland Utilities, Inc.		Suggest an illustration of R7 be added. R7 text states " ... due to the blowing together of vegetation and a conductor within an Active Transmission Line ROW". These words could suggest that sustained outages from vegetation (branches) extending within the active ROW, but originating from trees located outside the active ROW, might not be considered a preventable outage. An illustration in the reference paper would provide clarity.
Hydro-Quebec TransEnergie (HQT)		Suggest an illustration of R7 be added. R7 text states "... due to the blowing together of vegetation and a conductor within an Active Transmission Line ROW". These words could suggest that sustained outages from vegetation (branches) extending within the active ROW, but originating from trees located outside the active ROW, might not be considered a preventable outage. An illustration in the reference paper would provide clarity.Confusion still exists regarding the determination of the "active transmission line right-of-way". The diagrams shown in the white paper, though helpful, do not necessarily apply to all field conditions. Specific questions include: is it up to the Transmission Operator to determine the "active transmission line right-of-way", particularly in cases where the ROW may not be maintained to the legal boundary? Example 4 in the definition of "active transmission line right-of-way" (pg. 5) uses the words "deactivated" and "unavailable for service". The terms active, deactivated, and unavailable for service should be clearly defined as they can easily be interpreted different ways between different entities, and for different situations.
Independent Electricity System Operator		Suggest an illustration of R7 be added. R7 text states "... due to the blowing together of vegetation and a conductor within an Active Transmission Line ROW". These words could suggest that sustained outages from vegetation (branches) extending within the active ROW, but originating from trees located outside the active ROW, might not be considered a preventable outage. An illustration in the reference paper would provide clarity.Confusion still exists regarding the determination of the "active transmission line right-of-way". The diagrams shown in the white paper, though helpful, do not necessarily apply to all field conditions. Specific questions include: is it up to the Transmission Operator to determine the "active transmission line right-of-way", particularly in cases where the ROW may not be maintained to the legal boundary? Example 4 in the definition of "active transmission line right-of-way" (pg. 5) uses the words "deactivated" and "unavailable for service". The terms active, deactivated, and unavailable for service should be clearly defined as they can easily be interpreted different ways between different entities, and for different situations.
ISO New England Inc.		Suggest an illustration of R7 be added. R7 text states "... due to the blowing together of vegetation and a conductor within an Active Transmission Line ROW". These words could suggest that sustained outages from vegetation (branches) extending within the active ROW, but originating from trees located outside the active ROW, might not be considered a preventable outage. An illustration in the reference paper would provide clarity.Confusion still exists regarding the determination of the "active transmission line right-of-way". The diagrams shown in the white paper, though helpful, do not necessarily apply to all field conditions.

Organization	Yes or No	Question 14 Comment
		Specific questions include: is it up to the Transmission Operator to determine the “active transmission line right-of-way”, particularly in cases where the ROW may not be maintained to the legal boundary? Example 4 in the definition of “active transmission line right-of-way” (pg. 5) uses the words “deactivated” and “unavailable for service”. The terms active, deactivated, and unavailable for service should be clearly defined as they can easily be interpreted different ways between different entities, and for different situations.
Northeast Power Coordinating Council--RSC		Suggest an illustration of R7 be added. R7 text states “... due to the blowing together of vegetation and a conductor within an Active Transmission Line ROW”. These words could suggest that sustained outages from vegetation (branches) extending within the active ROW, but originating from trees located outside the active ROW, might not be considered a preventable outage. An illustration in the reference paper would provide clarity.Confusion still exists regarding the determination of the “active transmission line right-of-way”. The diagrams shown in the white paper, though helpful, do not necessarily apply to all field conditions. Specific questions include: is it up to the Transmission Operator to determine the “active transmission line right-of-way”, particularly in cases where the ROW may not be maintained to the legal boundary? Example 4 in the definition of “active transmission line right-of-way” (pg. 5) uses the words “deactivated” and “unavailable for service”. The terms active, deactivated, and unavailable for service should be clearly defined as they can easily be interpreted different ways between different entities, and for different situations.
Vegetation Management Team		The Active ROW definition should be expanded to exclude areas of the ROW that are currently being used for other transmission facilities, such as 110 kV towers etc. As written, it only excludes unused portions of the ROW, abandon lines and the side of structures that have no facilities. Perhaps use “A strip of land that is occupied by applicable transmission facilities.The last paragraph on page 8 of the Technical Reference indicates that the Standard is not applicable to “...line sections inside the electric station or other boundary...” This is somewhat ambiguous on who has the responsibility of assure compliance “inside the fence or other boundary”.
Salt River Project		The Active ROW should be defined in more detail.
Public Service Co. of New Mexico		The Planning Coordinator is not defined. Please clarify who this person(s) are.Additionally there needs to be more specific language regarding the importance of this reliability standard specifically for dealings with Federal, State or Tribal authorities.
American Electric Power		The SDT has done a great job developing this version of the standards, responding to comments, and enhancing the Technical Reference document. We have no other questions at this time.
Utility Arborist Association		The UAA commends the standards drafting team for covering ANSI A300, Part 7 and the International Society

Organization	Yes or No	Question 14 Comment
		of Arboriculture's integrated vegetation management best management practices in the technical reference. The UAA considers the treatment to be a reasonable representation of best practices to use in complying with FAC-003-02. We remain convinced that best management practice implementation is the most effective way to improve reliability. The A300 section in the technical reference is an important contribution in that regard. We reiterate our view that ANSI A300 be included in the requirements rather than as a footnote in the standard.
MRO NERC Standards Review Subcommittee		To avoid confusion, the diagrams of the ROWs in the White Paper should not have tree-like objects in the Active Transmission Right of Way. If any vegetation is to be shown in those areas, the vegetation should be shrubbery.
Northern Indiana Public Service Company		When discussing R4 (Pg. 30), the document brings up the concept of identifying encroachments of the MVCD during inspections but doesn't discuss indicators present in vegetation that has experienced flashover. For example, at the time vegetation is inspected, offending vegetation may be well outside the minumum distance in Table 1, but still exhibit evidence of sparkover such is wilted leaves, scorched limbs, etc. It would be helpful for the document to discuss these and other indicators of encroachment into the MVCD in greater detail.

15. As stated in the background information above, in response to industry comments, the applicability section is revised to replace Reliability Coordinator with Planning Coordinator. Do you agree with these changes? If not, please explain and propose an alternative.

Organization	Yes or No	Question 15 Comment
Entegra Power Group LLC		No comment
Tampa Electric Company		We do not agree or disagree on this Requirement.
Ameren	Agree	
American Electric Power	Agree	
American Transmission Company	Agree	
Arizona Public Service	Agree	
Associated Electric Cooperative, Inc.	Agree	
BC Transmission Corporation	Agree	
Bonneville Power Administration	Agree	
CenterPoint Energy	Agree	
Central Maine Power an Energy East Company	Agree	
Consolidated Edison Company of New York Inc.	Agree	

Organization	Yes or No	Question 15 Comment
Duke Energy	Agree	
Entergy Services, Inc	Agree	
FirstEnergy Corp	Agree	
Georgia Transmission Corporation	Agree	
Hydro One Networks inc.	Agree	
Hydro-Quebec TransEnergie (HQT)	Agree	
Idaho Power Company	Agree	
Independent Electricity System Operator	Agree	
ISO New England Inc.	Agree	
Lee County Electric Cooperative	Agree	
Manitoba Hydro	Agree	
National Grid	Agree	
Nebraska Public Power District	Agree	
NERC Standards Review Subcommittee	Agree	
New Brunswick Power Transmission	Agree	

Organization	Yes or No	Question 15 Comment
North Carolina Electric Membership Corporation	Agree	
Northeast Power Coordinating Council--RSC	Agree	
Northeast Utilities	Agree	
Northern Indiana Public Service Company	Agree	
Oncor Electric Delivery	Agree	
Orange and Rockland Utilities, Inc.	Agree	
Pacific Gas and Electric Co.	Agree	
PacifiCorp	Agree	
Progress Energy Carolinas, Inc.	Agree	
Puget Sound Energy	Agree	
ReliabilityFirst Corporation	Agree	
Salt River Project	Agree	
SCE&G	Agree	
SERC Vegetation Managment Sub-committee (VMS)	Agree	
Southern California Edison	Agree	

Organization	Yes or No	Question 15 Comment
Company		
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Transmission Owner	Agree	
Tucson Electric Power Company	Agree	
TVA	Agree	
TVA	Agree	
TVA	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Xcel Energy	Agree	
JEA	Agree	I agree this makes sense. Unfortunately, at least in FRCC, every TO has TWO Planning Coordinators so unless the RE or NERC straightens that situation out, there will be confusion as to which has the authority.
E.ON U.S.	Disagree	: E.ON U.S. recommends that the RC remain the responsible entity instead of the Planning Coordinator as RCs are best situated to determine a line's criticality to the region.

Organization	Yes or No	Question 15 Comment
Public Service Co. of New Mexico	Disagree	As stated in several earlier questions, there isn't a definition of who this person(s) are and what their duties are? Should be clearly defined in both the standard and in the white paper.
Pepco Holdings, Inc - Affiliates (PHI)	Disagree	PHI concurs with replacing the Reliability Coordinator with the Planning Coordinator. However, PHI has concerns with the Applicability section. 4.2.1 has (-applicable lines-) immediately following the term -transmission lines-, indicating that all Transmission Lines are applicable lines. We are certain that is not what the SDT meant. Additionally, Transmission Line is a NERC defined term and includes all Facilities 69kV - 765kV. We assume what is meant is to limit the applicability to BES (BPS) Facilities 200kV and above plus Transmission Lines operated below 200kV designated by the Planning Coordinator.PHI also encourages further consideration for lines from generation facilities to network substations. Some Generator Owners have lines greater than a mile in length. The SDT should consider whether to extend applicability of the standard for Generator Owners that own lines that meeting certain predefined criteria, or other approaches that would clarify the treatment of lines owned by Generator Owners on the generator side of a network substation.
Vegetation Management Team	Disagree	Suggest adding BES to the first bullet under A.4.-Facilities: to clarify that FAC-003-2 only applies to the BES. That radial lines supplying distribution substations, etc. aren't part of the standard. The bullet could read: "Bulk Electric System Transmission lines ("applicable lines") operated at 200kV or higher, and transmission lines operated below 200kV designated by the Planning Coordinator as being subject to this standard including but not limited to those that cross lands owned by federal1, state, provincial, public, private, or tribal entities."
US Bureau of Reclamation	Disagree	The role should be examined as part of the functional model description. To modify the role in the inidividual standards may result in holes in the fuctional model roles.
Platte River Power Authority Vegetation Management Group	Disagree	We are still finding confusion within the industry about the function of the Planning Coordinator and registration for Planning Coordinator (a.k.a. the Planning Authority). We think a strong possibility exists that there may be Transmission Owners who don't have a Planning Coordinator or assume that their Balancing Authority or a other registered entity is providing this function for them when in reality they are not. This confusion could present a gap in reliability. At one time there was discussion of removing this function from the Functional Model all together and replacing Planning Coordinator with Transmission Planner in all applicable standards. Although the Planning Coordinator and the Transmission Planner are the same within our organization we believe it will provide clarity to the standard to make it applicable to the Transmission Planner opposed to the Planning Coordinator. The coordination of the Transmission Planner would be between the Transmission Owners and neighboring transmission planners in R10.

Organization	Yes or No	Question 15 Comment
ISO/RTO Council	Agree	If this standard retains the need to identify sub 200KV facilities, then the change of this responsibility from the Reliability Coordinator to the Planning Coordinator is appropriate.

16. As stated in the background information above, in response to industry comments, changes were made to the definitions. Do you agree with these changes? If not, please explain and propose an alternative.

Organization	Yes or No	Question 16 Comment
Entegra Power Group LLC		No comment
American Electric Power	Agree	
American Transmission Company	Agree	
Arizona Public Service	Agree	
Associated Electric Cooperative, Inc.	Agree	
BC Transmission Corporation	Agree	
Central Maine Power an Energy East Company	Agree	
Consolidated Edison Company of New York Inc.	Agree	
Duke Energy	Agree	
E.ON U.S.	Agree	
Georgia Transmission Corporation	Agree	
Hydro One Networks inc.	Agree	

Organization	Yes or No	Question 16 Comment
Hydro-Quebec TransEnergie (HQT)	Agree	
Idaho Power Company	Agree	
Independent Electricity System Operator	Agree	
ISO New England Inc.	Agree	
JEA	Agree	
Lee County Electric Cooperative	Agree	
Nebraska Public Power District	Agree	
New Brunswick Power Transmission	Agree	
North Carolina Electric Membership Corporation	Agree	
Northeast Power Coordinating Council--RSC	Agree	
Northeast Utilities	Agree	
Northern Indiana Public Service Company	Agree	
Oncor Electric Delivery	Agree	
Orange and Rockland Utilities, Inc.	Agree	

Organization	Yes or No	Question 16 Comment
Pacific Gas and Electric Co.	Agree	
PacifiCorp	Agree	
Progress Energy Carolinas, Inc.	Agree	
Puget Sound Energy	Agree	
ReliabilityFirst Corporation	Agree	
SCE&G	Agree	
SERC Vegetation Managment Sub-committee (VMS)	Agree	
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tampa Electric Company	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Transmission Owner	Agree	
TVA	Agree	
TVA	Agree	
TVA	Agree	

Organization	Yes or No	Question 16 Comment
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Bonneville Power Administration	Agree	“Response Control Center” is not defined in the NERC Glossary of Terms, so it either needs to be added to the Glossary and/or defined within the Standard to be clear regarding its definition.
Edison Electric Institute	Agree	EEI also recommends that the SDT reconsider use of the term ‘applicable lines’ in the revised draft Standard or clarify the definition. The way the Standard is written with the term “applicable lines” in parentheses and quotes after the words “Transmission lines” in section 4, the term “applicable lines” would under normal interpretation rules be interpreted to mean “Transmission lines.” This surely is not the intent of the SDT. If “applicable lines” is meant to be the facilities defined in Section 4, then EEI recommends modifying Section 4 “Facilities” to read: “Facilities (‘applicable lines’)” if that is the intent to the term ‘applicable lines.’ If not, then the term needs a more specific definition.While applicability of the Standard is already described, use of this term in specific requirements could suggest that there may be lines that are otherwise subject to requirements of the Standard and only ‘applicable lines’ are addressed in some requirements. For example, the sentence ‘Sustained Outages of applicable lines that result from natural disaster,’ could be interpreted to refer to lines affected by a natural disaster, or some other subset of all lines subject to the Standard. EEI recommends that the SDT consider revising language of this type to remove the phrase ‘applicable lines.’ In the example cited, the sentence would become a clause reading: ‘Sustained Outages that result from natural disasters.’
National Grid	Agree	National Grid agrees with the new definition for active transmission right-of-way, though it may need further clarification in the Technical reference document. We have concerns that TO’s might consider portions of the original ROW width as not active. For example: Original width of a ROW was 100 feet, however over many decades the maintained width has been reduced to 80 feet. Might the new definition provide incentive for the TO to now define the active ROW as 80 feet? The proposed removal of the requirement to report Category 3 sustained outages provides additional incentive for the TO to adopt this approach.
Southern California Edison Company	Agree	SCE generally agrees with the definitions, but suggests that the "Vegetation Inspection" definition be revised to read: Vegetation Inspection - The systematic examination of vegetation conditions within an Active Transmission Line Right of Way. A Vegetation Inspection may be combined with other transmission facility inspections.

Organization	Yes or No	Question 16 Comment
FirstEnergy Corp	Agree	We agree with the definitions, but want to point out that this is the only standard that would utilize the term Vegetation Inspection, and the current definition is not used anywhere in the currently approved set of NERC standards. Should this definition only be specific to this standard and not a NERC glossary term? Regardless, we do not have an issue either way.
Xcel Energy	Disagree	(a) The definition of Active Transmission Line Right of Way is confusing. There may be other portions of the Right of Way that were not specifically acquired for other facilities (or being used for other facilities), but are not used and are not needed. As drafted, this definition would ignore this fact. Further, by limiting the definition in this manner, it ignores the fact that it may take different portions of the right of way to operate the line (due to the characteristics of the line, size, location, etc.) and address vegetation concerns. It would be more accurate if the “intended for other facilities” portion of the definition were deleted. This would allow the flexibility to address the concerns noted above. Thus it would read: "A strip of land that is occupied by active transmission facilities. This corridor does not include the inactive or unused part of the right of way."(b) The definition of “Vegetation Inspection” should be rewritten to change the documentation requirement for any vegetation which “may pose a threat.” As a practical mater, any vegetation “may” pose a threat. The definition would be better phrased to read: "The systematic examination of vegetation conditions on an Active Transmission Line Right of Way. This inspection may be combined with a general line inspection. The inspection includes the documentation of any vegetation that poses an unacceptable risk to reliability prior to the next planned inspection or maintenance work."
Platte River Power Authority Vegetation Management Group	Disagree	“intended for other facilities” should be struck from the definition of Active Transmission Line Right of Way as it may include deactivated transmission lines, buffer zones or other ROW never intended for other facilities but wider that necessary.
Tucson Electric Power Company	Disagree	1- In the definition of the term “Active Transmission Right of Way” the final sentence should read “This corridor does not include the inactive or unused part of the Right of Way.” Delete intended for other facilities. 2- We propose the following modification to the Vegetation Inspection definition the sentence; “The inspection includes the documentation of any vegetation that may pose a threat unacceptable risk to reliability prior to the next planned inspection or maintenance work”. This would make the language consistent with other language found in M11 of this document.
MRO NERC Standards Review Subcommittee	Disagree	A. The definition of Active Transmission Line Right of Way is confusing. There may be other portions of the Right of Way that were not specifically acquired for other facilities (or being used for other facilities), but are not used and are not needed. It would be more accurate if the text “intended for other facilities” was deleted. Thus it would read: “A strip of land that is occupied by active transmission facilities. This corridor does not include the inactive or unused part of the right of way.”B. The definition of “Vegetation Inspection” should be

Organization	Yes or No	Question 16 Comment
		rewritten to change the documentation requirement for any vegetation which "may pose a threat." As a practical matter, any vegetation "may" pose a threat. The definition would be better phrased to read: "The systematic examination of vegetation conditions on an Active Transmission Line Right of Way. This inspection may be combined with a general line inspection. The inspection includes the documentation of any vegetation that poses an unacceptable risk to reliability prior to the next planned inspection or maintenance work."
Pepco Holdings, Inc - Affiliates (PHI)	Disagree	Active Transmission Line Right of Way should include the buffer needed to maintain clearances. Width needs to be sufficient to maintain clearances. This should be identified by the TO.
CenterPoint Energy	Disagree	Active Transmission Line Right of WayCenterPoint Energy disagrees with the inclusion and definition of "Active Transmission Line Right of Way". "Active Transmission Line Right of Way" is not defined as to its geometric limits within the Standard. The SDT has indicated in its response to 1st Draft Comments from CenterPoint Energy that the "...Transmission Owner is responsible for defining the Active Transmission Line Right of Way." However, that defining clause is not included in the current definition. CenterPoint Energy recommends one of the following options in order of preference:1) Recommend deleting the term "Active Transmission Line Right of Way" from the standard and revising the Requirements, Measures, and Compliance line items accordingly. R1.6 already requires that maintenance strategies ensure that the MVCD is never violated and considers "the sag and sway of the conductor throughout is operating range and under rated conditions". This requirement by itself defines the airspace that must be maintained to prevent a Sustained Outage for grow-ins and blow-ins. R7 would be revised to read "Each Transmission Owner shall prevent Sustained Outages of applicable lines due to the blowing together of vegetation and a conductor operating within its designed sway under rated conditions with the following exceptions...".R8 would be revised to read, "Each Transmission Owner shall prevent Sustained Outages of applicable lines due to vegetation falling into a conductor where the Transmission Owner had the legal right or prior permission to remove the vegetation."2) To parallel the requirement of R1.6, revise the definition of "Active Transmission Line Right of Way" to, "A strip of land that is occupied by applicable lines considering the sag and sway of the conductor throughout its operating range under rated conditions plus the Minimum Vegetation Clearance Distance (MVCD) from Table 1, where applicable lines are defined as transmission lines operating in real time at 200kV or higher and transmission lines operating in real time below 200kV designated by the Planning Coordinator as being subject to this standard, including but not limited to those lines that cross lands owned by federal, state, provincial, public, private, or tribal entities."3) If the SDT and NERC intend for the Active Transmission Line Right of Way limits to be determined based on the Transmission Owner's interpretation, CenterPoint Energy suggests an alternate definition as follows, "Active Transmission Line Right of Way - A strip of land, the dimensions of which are determined by the Transmission Owner, occupied by applicable lines, where applicable lines are defined as transmission lines operating in real time at 200kV or higher and transmission lines operating in real time below 200kV designated by the Planning Coordinator as being

Organization	Yes or No	Question 16 Comment
		subject to this standard, including but not limited to those lines that cross lands owned by federal, state, provincial, public, private, or tribal entities."By making this suggested change to the definition of "Active Transmission Line Right of Way", most of the ambiguity is removed. It is now clear that the standard does not apply to those portions of rights-of-way in which there are no applicable lines, such as 69kV and 138kV lines that the Planning Coordinator has not determined to be subject to the standard. CenterPoint Energy has added the phrase "operating in real time" to make it clear that the standard also does not apply to a right-of-way in which there is a non-operating line which would normally be subject to the standard if it was operating. By adding MVCD and "sag and sway" requirements to the definition of "Active Transmission Line Right of Way", the standard has defined the physical limits necessary to determine if there has been a violation from trees adjacent to the applicable lines. The alternate definition without the MVCD citation clarifies who is to determine the physical limits of the Active Transmission Line Right of Way since none are provided in the definition itself. However, adding such a reference would surmount to a "fill-in-the-blank" requirement which the SDT has found undesirable. Vegetation InspectionCenterPoint Energy disagrees with the definition of "Vegetation Inspection" since it includes the term "Active Transmission Line Right of Way" which is ambiguously defined and not relevant to defining the type of inspection performed. CenterPoint Energy recommends the following definition, "Vegetation Inspection - The systematic examination of vegetation conditions under and adjacent to a transmission line considering the current location of the conductor and other possible locations of the conductor due to sag and sway for rated conditions. This inspection may be combined with a general line inspection. The inspection includes the documentation of any vegetation that may pose a threat to reliability prior to the next planned inspection or maintenance work."
Salt River Project	Disagree	For the definition of "Vegetation Inspection" recommend the following changes:- In the 3rd sentence, the use of "threat", change to "unacceptable risk"- In the 3rd sentence, remove the last statement "...consider the current location of the conductor and other possible locations of the conductor due to sag and sway for rated conditions". The definition is too lengthy and it does not appear this additional language is necessary.
Vegetation Management Team	Disagree	MVCZ should be included in the Definitions of Terms Used in Standard.
Public Service Co. of New Mexico	Disagree	PNM recommends ammending the definition of "Active Transmission Line Right of Way" as follows: A strip of land that is occupied by active transmission facilities. This corridor does not include the inactive or unused part of the Right of Way.PNM recommends ammending "Vegetation Inspection" to include acceptable types of inspection methods i.e. ground patrols, aerial patrols, etc.
Entergy Services, Inc	Disagree	See additional Entergy comments below.
Manitoba Hydro	Disagree	the definition of "active ROW" should include the concept of meeting safe/reliable operation design criteria

Organization	Yes or No	Question 16 Comment
US Bureau of Reclamation	Disagree	The definitions should not include performance measures or suggestions such as "This inspection may be combined with a general lineinspection." The definition is also phrased in terms of a requirement by using "The inspection includes the documentation of any vegetation that may pose a threatto reliability prior to the next planned inspection or maintenance work, considering the current location of the conductor and other possible locations of the conductor due to sag and sway for rated conditions." Both of these quoted phrases should be removed to the requirements section.
Ameren	Disagree	Vegetation Inspection:Need to insert that these inspections are based on inspectors expectation of normal growth and environmental factors or note that the inspector can not determine all hazards from vegetation that may occur from natural disasters or human or animal activity when inspecting. This would be a complimentary statement to the exceptions for actual events that occur in these requirements.
ISO/RTO Council		The SRC has no comment on this question.

17. When compared to Version 1, does this proposed Version 2 of the standard either maintain or improve overall electric reliability? Please provide a technical basis for your response?

Organization	Does or Does Not	Question 17 Comment
Entegra Power Group LLC		No comment
Southern California Edison Company		Uncertain. At this point in time, SCE does not believe that it is possible to predict whether Version 2 will improve overall electric reliability when compared with Version 1 because NERC has not yet demonstrated with documentation that the implementation of Version 1 of FAC-003 has improved electric reliability.
Ameren	V2 Does maintain or improve overall reliability	
CenterPoint Energy	V2 Does maintain or improve overall reliability	
Central Maine Power an Energy East Company	V2 Does maintain or improve overall reliability	
Duke Energy	V2 Does maintain or improve overall reliability	
Entergy Services, Inc	V2 Does maintain or improve overall reliability	
FirstEnergy Corp	V2 Does maintain or improve overall reliability	

Organization	Does or Does Not	Question 17 Comment
Georgia Transmission Corporation	V2 Does maintain or improve overall reliability	
Idaho Power Company	V2 Does maintain or improve overall reliability	
Lee County Electric Cooperative	V2 Does maintain or improve overall reliability	
Manitoba Hydro	V2 Does maintain or improve overall reliability	
Nebraska Public Power District	V2 Does maintain or improve overall reliability	
Northeast Utilities	V2 Does maintain or improve overall reliability	
Oncor Electric Delivery	V2 Does maintain or improve overall reliability	
Pacific Gas and Electric Co.	V2 Does maintain or improve overall reliability	
Pepco Holdings, Inc - Affiliates (PHI)	V2 Does maintain or improve overall reliability	

Organization	Does or Does Not	Question 17 Comment
Platte River Power Authority Vegetation Management Group	V2 Does maintain or improve overall reliability	
Progress Energy Carolinas, Inc.	V2 Does maintain or improve overall reliability	
ReliabilityFirst Corporation	V2 Does maintain or improve overall reliability	
Tenessee Valley Authority	V2 Does maintain or improve overall reliability	
Transmission Owner	V2 Does maintain or improve overall reliability	
Tucson Electric Power Company	V2 Does maintain or improve overall reliability	
TVA	V2 Does maintain or improve overall reliability	
TVA	V2 Does maintain or improve overall reliability	
TVA	V2 Does maintain or improve overall reliability	

Organization	Does or Does Not	Question 17 Comment
Vegetation Management Team	V2 Does maintain or improve overall reliability	
WECC RC	V2 Does maintain or improve overall reliability	
Xcel Energy	V2 Does maintain or improve overall reliability	
SCE&G	V2 Does maintain or improve overall reliability	As stated, SCE&G believes that this standard version is superior to the previous. Improvement areas include: o Clarification is made that sustained outages are a violation of the requirements. o Separation of imminent threat, vegetation inspections and the annual work-plan have been made. o Minimum clearance distances are realistic and eliminates references outside the standard (via Appendix 1). The fill-in-the-blank aspects are eliminated. o Established a clear process for identifying sub 200kV circuits applicable to the revised standard. o Clarification of the active ROW o This revision eliminates non enhancing aspects of the previous version (e.g. personnel qualifications, category 3 reporting, clearance 1, etc.) o Applies to applicable transmission facilities regardless of location o Focus is made to actual and observable conditions rather than hypothetical conditions. o Addresses the elements of FERC order 693
SERC Vegetation Managment Sub-committee (VMS)	V2 Does maintain or improve overall reliability	As stated, the SERC VMS believes that this standard version is superior to the previous. These improvements include:Clarification is made that sustained outages are a violation of the requirements. Separation of imminent threat, vegetation inspections and the annual work-plan have been made. Minimum clearance distances are realistic and eliminates references outside the standard (via Appendix 1). The fill-in-the-blank aspects are eliminated. It establishes a clear process for identifying sub 200kV circuits applicable to the revised standard. Clarification of the active ROW is made.This revision eliminates non enhancing aspects of the previous version (e.g. personnel qualifications, category 3 reporting, clearance 1, etc.)Applies to applicable transmission facilities regardless of location.Focus is made to actual and observable conditions rather than hypothetical conditions.It addresses the elements of FERC order 693.
American Transmission	V2 Does maintain or improve overall	ATC believes that the standard provides for improved reliability, however, needs to consider ATC’s

Organization	Does or Does Not	Question 17 Comment
Company	reliability	comments to earlier questions.
Bonneville Power Administration	V2 Does maintain or improve overall reliability	BPA believes V2 maintains overall reliability. Although there are many differences between the two versions, the overall differences between version 1 and version 2 appear to have the same impact on reliability.
Consolidated Edison Company of New York Inc.	V2 Does maintain or improve overall reliability	CECONY believes that the Standard does help maintain or improve overall reliability since the requirements for a TVMP are clearly addressed including inspection cycles, responses to imminent threats, reduced ambiguity, and documentation requirements. Also, the fact that real time encroachments are considered violations will make utilities more likely to use LIDAR and other technology without the fear of discovery of an encroachment violation of a condition that has not occurred. This will result in earlier detection of potential problems and will increase reliability. The Transmission Owner should be solely responsible for determining the abilities and training needs of their employees and ensure that capable individuals perform their vegetation management functions.
E.ON U.S.	V2 Does maintain or improve overall reliability	E.ON U.S. believes the proposed revision provides much greater clarity to the requirements than what is currently in place.
Edison Electric Institute	V2 Does maintain or improve overall reliability	EEI applauds the commitment and effort of the SDT and appreciates the revised draft FAC-003 Standard as a complete response to the key issues raised by FERC in Order No. 693:o NERC has addressed applicability issues, balancing the need for covering facilities that impact reliability against unreasonably increasing the burden of transmission owners.o NERC has addressed minimum clearance issues, proposing requirements that will avoid vegetation-related sustained outages for lines on both federal and non-federal lands.o NERC has proposed changes to applicability to better recognize differing needs for active and inactive rights-of-way. o NERC has addressed inspection cycles to ensure that inspections are conducted at reasonable intervals.Overall, EEI believes that the Standard can provide adequate requirements for company vegetation management programs for maintaining clearances on rights-of-way on the Bulk Power System. Compliance with these requirements would, if established as mandatory by FERC, support reliable operation of the Bulk Power System by preventing Sustained Outages caused by vegetation.The electric industry broadly recognizes that several Reliability Standards contain ambiguous terms and requirements, which have resulted in significant challenges for companies in seeking to determine appropriate compliance actions, and for compliance enforcement activities within NERC. EEI strongly supports the general process for improving the Standards development process and content of the Standards as a long-term goal for NERC. In the context of revising

Organization	Does or Does Not	Question 17 Comment
		FAC-003, to the maximum extent practicable EEI encourages the SDT to use defined terms and explicit references. EEI recognizes also that the need to reduce ambiguity must be balanced against the need to adapt flexible requirements and measures that recognize the widely varying vegetation circumstances on the Bulk Power System. This is especially challenging for developing enforceable requirements to address vegetation encroachment issues on transmission rights-of-way.
Tennessee Valley Authority	V2 Does maintain or improve overall reliability	I believe it improves reliability.
Associated Electric Cooperative, Inc.	V2 Does maintain or improve overall reliability	It is Associated Electric Cooperative Inc's opinion that V2 maintains overall reliability as compared to V1. o Developing separate requirements for documentation and implementation of the Imminent Threat Process, Vegetation Inspections, and the Annual Work Plan adds to the clarity of the standard.
North Carolina Electric Membership Corporation	V2 Does maintain or improve overall reliability	NCEMC does believe that this standard version is an improvement to the previous. Improvement areas include:o Clarification is made that sustained outages are a violation of the requirements. o Separation of imminent threat, vegetation inspections and the annual work-plan have been made. o Minimum clearance distances are realistic and eliminates references outside the standard (via Appendix 1). The fill-in-the-blank aspects are eliminated. o Established a clear process for identifying sub 200kV circuits applicable to the revised standard. o Clarification of the active ROW.o This revision eliminates non enhancing aspects of the previous version (e.g. personnel qualifications, category 3 reporting, clearance 1, etc.)o Applies to applicable transmission facilities regardless of locationo Focus is made to actual and observable conditions rather than hypothetical conditions.o Addresses the elements of FERC order 693
Southern Company	V2 Does maintain or improve overall reliability	The new standard differentiates between IROL and non IROL facilities. The use of the Planning Coordinator in lieu of the Reliability Coordinator provides a long term approach to improving reliability. The definition of active ROW helps differentiate between important ROW and less important ROW.
Western Area Power Administration, Rocky Mountain Region	V2 Does maintain or improve overall reliability	The proposed Version 2 of the Standard improves overall system reliability by: 1) Clarifying previously ambiguous requirements of Version 1 regarding what is or is not a violation of the Standard. For example, previously unclear expectations associated with Version 1 requirements R1.2.2. and R3 are now clearly addressed as requirements in Version 2 requirements R4, R5, R6,

Organization	Does or Does Not	Question 17 Comment
		R7 and R8. 2) Providing real time, observable and measurable thresholds for compliance in Version 2 verses the many subjective and "interpreted" thresholds for compliance which were contained in Version 1 requirements. 3) Requiring a series of pro-active, mandatory and graduated actions by the Transmission Owner for preventing vegetation related outages that could lead to cascading events. These "layers of protection" include the formal identification of facilities subject to the standard, the establishment of a credible TVMP and execution of annual plans, mandatory field inspections, prevention of encroachments into Minimum Vegetation Clearance Distances, mitigation of imminent threats, prevention of outages due to fall ins, prevention of outages due to blow ins, and the prevention of outages due to grow ins.
JEA	V2 Does maintain or improve overall reliability	The standard seems to maintain reliability and add clarity.
American Electric Power	V2 Does maintain or improve overall reliability	This standard is a significant improvement in its specificity of the documentation and reporting responsibilities necessary to be fully compliant.
MRO NERC Standards Review Subcommittee	V2 Does maintain or improve overall reliability	Using the Gallet equation puts the tree trimmers closer to the lines than the OSHA standards will allow due to the fact that OSHA recognizes the standard IEEE 516-2003 clearance distances. We recommend revising Table 1 taking into account the IEEE standard.
New Brunswick Power Transmission	V2 Does maintain or improve overall reliability	V2 is a much improved version of the standard in that it provides clarify on a number of issues; the technical reference is a welcome addition and provides critical information for meeting proposed standard.
Superintendent Transmission Maintenance	V2 Does maintain or improve overall reliability	V2 maintains and improves overall system reliability with real-time, observable, and measurable standards that include a thorough approach (inspections, reporting, MVCDs, etc) to minimizing cascading outages caused by vegetation.
Tampa Electric Company	V2 Does maintain or improve overall reliability	V2 represents the growth of the standard via much improved clarification; I have to think that this will result in a much better overall industry understanding of the standard and its requirements. This should result in improved Industry performance and thus will maintain or improve overall reliability. MVCD is improved via Gallet formula, definitions are new & improved, VRF & VSL’s clarify risk and severity.

Organization	Does or Does Not	Question 17 Comment
US Bureau of Reclamation	V2 Does not maintain or improve overall reliability	It is hard to imagine any vegetation encroachment that would not be exempted by this standard. Overall the exemptions appear to be inconsistent with the language in the respective requirements.
National Grid	V2 Does not maintain or improve overall reliability	National Grid disagrees that V2 will improve reliability for 3 reasons: 1) National Grid believes eliminating Clearance 1 will be detrimental to reliability. The determination of Clearance 1 is an important exercise for the TO to better understand the dynamics of conductor movement and vegetative growth. This required analysis should lead to development of a more informed vegetation management program. Clearance 1 also gives the TO leverage with landowners and local regulators to achieve the necessary operational clearances. If the only required clearance is the R4 Minimum Vegetation Clearance Distance (MVCD), landowners and local regulators will push the utility to maintain a clearance close to the MVCD. 2) National Grid believes eliminating the reporting of Category 3 sustained outages will lead to less effort by the TO's to mitigate danger tree exposure where the TO's property rights allow. This will lead to diminished reliability. 3) Removing the qualifications requirement from the standard will likely lead to TO's employing less qualified employees and contractors. The Utility Vegetation Management (UVM) industry, through development of ANSI Standards and industry Best Practices, and the International Society of Arboriculture certification programs, has worked to raise the level of professionalism in the UVM industry. National Grid believes that raising professional standards leads to better quality work and improved reliability.
Orange and Rockland Utilities, Inc.	V2 Does not maintain or improve overall reliability	ORU disagrees that V2 will improve reliability for 3 reasons: 1) ORU believes eliminating Clearance 1 will be detrimental to reliability. The determination of Clearance 1 is an important exercise for the TO to better understand the dynamics of conductor movement and vegetative growth. This required analysis should lead to development of a more informed vegetation management program. Clearance 1 also gives the TO leverage with landowners and local regulators to achieve the necessary operational clearances. If the only required clearance is the R4 Minimum Vegetation Clearance Distance (MCVD), landowners and local regulators will push the utility to maintain a clearance close to the MVCD. 2) ORU believe eliminating the reporting of Category 3 sustained outages will lead to less effort by the TO's to mitigate danger tree exposure where the TO's property rights allow. This will lead to diminished reliability. 3) Removing the qualifications requirement from the standard will likely lead to TO's employing less qualified employees and contractors. The Utility Vegetation Management (UVM) industry, through development of ANSI Standards, and the International Society of Arboriculture certification programs have worked to raise the level of professionalism in the UVM industry. We believe that raising professional standards leads to better quality work and improved reliability. ORU believes that the Standard

Organization	Does or Does Not	Question 17 Comment
		does help maintain or improve overall reliability since the requirements for a TVMP are clearly addressed including inspection cycles, responses to imminent threats, and documentation requirements. Also, the fact that real time encroachments are considered violations will make utilities more likely to use LIDAR and other technology without the fear of discovery of an encroachment violation of a condition that has not occurred. This will result in earlier detection of potential problems and will increase reliability. Even though the Clearance 1 value is being eliminated from the Standard, operating specifications will still govern the way a utility handles its clearances as is currently done. We do agree, however, that landowners and local regulators may want utilities to reduce operational clearance levels based on the MVCD listed in the Standard but the utility must properly communicate the reasoning behind achieving greater clearances as per their TVMP. We do not believe that eliminating the reporting of Category 3 sustained outages will lead to less effort to mitigate danger tree exposure since all transmission outages are sensitive to a Transmission Owner and must be addressed appropriately at multiple levels within the company as well as with other regulatory agencies in some cases. Removing the qualifications requirement may initially lead to Transmission Owners employing less qualified employees and contractors but there needs to be some level of flexibility that will allow for a larger candidate pool or temporary support since individuals with specialized training are not always readily available. The Transmission Owner should be solely responsible for determining the abilities and training needs of their employees and ensure that capable individuals perform their vegetation management functions.
PacifiCorp	V2 Does not maintain or improve overall reliability	PacifiCorp disagrees that FAC-003-02 will improve reliability because the standard lacks a requirement to adhere to best management practices, it does not mandate that programs be managed by qualified individuals, and it has no clearance 1.
Arizona Public Service	V2 Does not maintain or improve overall reliability	Removing the following sections from FAC-003 version 1 does not improve or maintain reliability; R1.2.1, R1.3. APS has responded in the section above.
Puget Sound Energy	V2 Does not maintain or improve overall reliability	The elimination of Clearance 1 from the current standard, and the close distance to the wire in the proposed Table 1 will create more difficulty with agencies and reluctant landowners. A closer distance to the MVCD will be pushed by some. This revised standard gives Transmission Owner no leverage for maintaining Utiltiy Vegetation management Best Management Practices (BMP). If BMP's were utilitzed consistently, there would be minimum outages.
Salt River Project	V2 Does not maintain or improve overall	The proposed MVCD values are less than SRP has defined in the current standard for Clearance 2 values and would not provide adequate clearance. Also see comments stated in question #4

Organization	Does or Does Not	Question 17 Comment
	reliability	regarding concern regarding the method used to determine the MVCD values.
Utility Arborist Association	V2 Does not maintain or improve overall reliability	The Utility Arborist Association thinks version 2 does not improve reliability over version 1 for two reasons. It does not have a qualification requirement, and it does not contain a requirement for utilities to conform to ANSI A300.First, the UAA considers removal of the qualification requirement from the standard to detract from reliability compared to FAC-003-01. Appropriate qualifications are every bit as critical for vegetation management as they are for other areas of expertise necessary to operate the electric grid. For example, no utility would assign engineering responsibilities to anyone without engineering training and experience, as the electric grid would quickly fail. Yet, it is common for utilities to assign vegetation management oversight to employees without the appropriate knowledge and background to succeed. Consider that none of the three North American blackouts in the past fifteen years occurred solely due to engineering deficiencies. Rather, they were initiated by tree contacts. More effective vegetation management programs would have prevented every one of them. Clearly vegetation management expertise is critical, as the consequences of vegetation management deficiencies have resulted in three catastrophic grid failures. It cannot be left to people with improper or inadequate competencies. The standard should say as much.The Utility Arborist Association recognizes that the qualification requirement has been removed due to industry reaction to unreasonable and overbearing demands for proof of qualifications on the part of some auditors. For example, several utilities complained that auditors required resumes of everyone in the program, including ground workers. Clearly, that goes well beyond what was intended in the FAC-003-01, which was that vegetation management oversight for a transmission operator be in the hands of knowledgeable and competent managers. Arguably, demands for resumes of everyone remotely involved detracts from an effective program by occupying managers with irrelevant paper work, rather than addressing the demands of protecting their systems. On the other hand, poor judgment on the part of some auditors doesn't reduce the need for programs to be designed and implemented by qualified utility arborists. The Utility Arborist Association understands the need to address deficiencies in aptitude among vegetation management auditors, and is responding by developing training programs for them. Our objective is to raise the level of understanding among vegetation management auditors to a level necessary for consistent, fair and reasonable compliance oversight that will contribute to, rather than detract from, electric reliability.Secondly, the Utility Arborist Association considers limiting a reference to ANSI A300 to a footnote to insufficiently emphasize it's criticality to overall electric reliability. The UAA strongly urges adding language to R1.1 and M1.6, and hold utilities accountable for using best management practices. The Utility Arborist Association has worked hard to incorporate sufficient flexibility into integrated vegetation management best management practices to account for the array of environmental, political and technical challenges that might confront vegetation managers anywhere they practice. The Utility Arborist Association is confident that adding them as

Organization	Does or Does Not	Question 17 Comment
		requirements to the standard will improve reliability by raising professionalism and leading to more effective results.
Northern Indiana Public Service Company	V2 Does not maintain or improve overall reliability	There are many instances where V2 contains requirements and/or measures are weaker or less stringent than V1. Examples:1. Elimination of Clearance 1 requirements which have been so instrumental in improving T.O. vegetation maintenance activities on R.O.W.'s (see my comments from Draft 1 of FAC-003-2).2. Elimination of requirement for personnel responsible for design and implementation of TVMPs to hold appropriate qualifications to do so.3. Limitation of Corrective Action Process or Mitigation Measures to instances of temporary constraints to planned work rather than all constraints to planned work.4. Nesting the provision for T.O.'s to develop minimum vegetation to conductor clearances that ensure MVCDs are never violated within a general requirement to specify maintenance strategies. This needs to be a clear stand alone clearance requirement similar to the existing Clearance 2.
BC Transmission Corporation	V2 Does not maintain or improve overall reliability	This is a vegetation outage standard not a vegetation management standard. It will do nothing to improve the quality of vegetation maangement programs in North America
Northeast Power Coordinating Council--RSC	V2 Does not maintain or improve overall reliability	V2 will not improve reliability for the following reasons. Eliminating Clearance 1 will be detrimental to reliability. The determination of Clearance 1 is an important exercise for the TO to better understand the dynamics of conductor movement and vegetative growth. This required analysis should lead to development of a more informed vegetation management program. Clearance 1 also gives the TO leverage with landowners and local regulators to achieve the necessary operational clearances. If the only required clearance is the R4 Minimum Vegetation Clearance Distance (MCVD), landowners and local regulators will push the utility to maintain a clearance close to the MVCD. This will lead to diminished reliability. In some respects the Standard does help maintain or improve overall reliability since the requirements for a TVMP are clearly addressed including inspection cycles, responses to imminent threats, and documentation requirements. Also, the fact that real time encroachments are considered violations will make utilities more likely to use LIDAR (radar) and other technology without the fear of discovery of an encroachment violation of a condition that has not occurred. This will result in earlier detection of potential problems and will increase reliability. Even though the Clearance 1 value is being eliminated from the Standard, operating specifications will still govern the way a utility handles its clearances as is currently done. We do agree, however, that landowners and local regulators may want utilities to reduce operational clearance levels based on the MVCD listed in the Standard, but the utility must properly communicate the reasoning behind achieving greater clearances as per their TVMP. We do not believe that eliminating the reporting of Category 3 sustained outages will lead to less effort to

Organization	Does or Does Not	Question 17 Comment
		mitigate danger tree exposure since all transmission outages are sensitive to a Transmission Owner and must be addressed appropriately at multiple levels within the company as well as with other regulatory agencies in some cases. Removing the qualifications requirement may initially lead to Transmission Owners employing less qualified employees and contractors but there needs to be some level of flexibility that will allow for a larger candidate pool or temporary support since individuals with specialized training are not always readily available. The Transmission Owner should be solely responsible for determining the abilities and training needs of its employees and ensure that capable individuals perform their vegetation management functions.
Independent Electricity System Operator	V2 Does not maintain or improve overall reliability	V2 will not improve reliability for the following reasons. Eliminating Clearance 1 will be detrimental to reliability. The determination of Clearance 1 is an important exercise for the TO to better understand the dynamics of conductor movement and vegetative growth. This required analysis should lead to development of a more informed vegetation management program. Clearance 1 also gives the TO leverage with landowners and local regulators to achieve the necessary operational clearances. If the only required clearance is the R4 Minimum Vegetation Clearance Distance (MCVD), landowners and local regulators will push the utility to maintain a clearance close to the MVCD. This will lead to diminished reliability. The Standard does help maintain or improve overall reliability since the requirements for a TVMP are clearly addressed including inspection cycles, responses to imminent threats, and documentation requirements. Also, the fact that real time encroachments are considered violations will make utilities more likely to use LIDAR (radar) and other technology without the fear of discovery of an encroachment violation of a condition that has not occurred. This will result in earlier detection of potential problems and will increase reliability. Even though the Clearance 1 value is being eliminated from the Standard, operating specifications will still govern the way a utility handles its clearances as is currently done. We do agree, however, that landowners and local regulators may want utilities to reduce operational clearance levels based on the MVCD listed in the Standard, but the utility must properly communicate the reasoning behind achieving greater clearances as per their TVMP. We do not believe that eliminating the reporting of Category 3 sustained outages will lead to less effort to mitigate danger tree exposure since all transmission outages are sensitive to a Transmission Owner and must be addressed appropriately at multiple levels within the company as well as with other regulatory agencies in some cases. Removing the qualifications requirement may initially lead to Transmission Owners employing less qualified employees and contractors but there needs to be some level of flexibility that will allow for a larger candidate pool or temporary support since individuals with specialized training are not always readily available. The Transmission Owner should be solely responsible for determining the abilities and training needs of their employees and ensure that capable individuals perform their vegetation management functions.

Organization	Does or Does Not	Question 17 Comment
ISO New England Inc.	V2 Does not maintain or improve overall reliability	V2 will not improve reliability for the following reasons: 1) eliminating Clearance 1 will be detrimental to reliability. The determination of Clearance 1 is an important exercise for the TO to better understand the dynamics of conductor movement and vegetative growth. This required analysis should lead to development of a more informed vegetation management program. Clearance 1 also gives the TO leverage with landowners and local regulators to achieve the necessary operational clearances. If the only required clearance is the R4 Minimum Vegetation Clearance Distance (MCVD), landowners and local regulators will push the utility to maintain a clearance close to the MVCD. 2) Eliminating the reporting of Category 3 sustained outages will lead to less effort by the TO's to mitigate danger tree exposure where the TO's property rights allow. This will lead to diminished reliability. The Standard does help maintain or improve overall reliability since the requirements for a TVMP are clearly addressed including inspection cycles, responses to imminent threats, and documentation requirements. Also, the fact that real time encroachments are considered violations will make utilities more likely to use LIDAR (radar) and other technology without the fear of discovery of an encroachment violation of a condition that has not occurred. This will result in earlier detection of potential problems and will increase reliability. Even though the Clearance 1 value is being eliminated from the Standard, operating specifications will still govern the way a utility handles its clearances as is currently done. We do agree, however, that landowners and local regulators may want utilities to reduce operational clearance levels based on the MVCD listed in the Standard, but the utility must properly communicate the reasoning behind achieving greater clearances as per their TVMP. We do not believe that eliminating the reporting of Category 3 sustained outages will lead to less effort to mitigate danger tree exposure since all transmission outages are sensitive to a Transmission Owner and must be addressed appropriately at multiple levels within the company as well as with other regulatory agencies in some cases. Removing the qualifications requirement may initially lead to Transmission Owners employing less qualified employees and contractors but there needs to be some level of flexibility that will allow for a larger candidate pool or temporary support since individuals with specialized training are not always readily available. The Transmission Owner should be solely responsible for determining the abilities and training needs of their employees and ensure that capable individuals perform their vegetation management functions.
Hydro-Quebec TransEnergie (HQT)	V2 Does not maintain or improve overall reliability	V2 will not improve reliability for the following reasons:. Eliminating Clearance 1 will be detrimental to reliability. The determination of Clearance 1 is an important exercise for the TO to better understand the dynamics of conductor movement and vegetative growth. This required analysis should lead to development of a more informed vegetation management program. Clearance 1 also gives the TO leverage with landowners and local regulators to achieve the necessary operational clearances. If the only required clearance is the R4 Minimum Vegetation Clearance Distance

Organization	Does or Does Not	Question 17 Comment
		(MCVD), landowners and local regulators will push the utility to maintain a clearance close to the MVCD. This will lead to diminished reliability. The Standard does help maintain or improve overall reliability since the requirements for a TVMP are clearly addressed including inspection cycles, responses to imminent threats, and documentation requirements. Also, the fact that real time encroachments are considered violations will make utilities more likely to use LIDAR (radar) and other technology without the fear of discovery of an encroachment violation of a condition that has not occurred. This will result in earlier detection of potential problems and will increase reliability. Even though the Clearance 1 value is being eliminated from the Standard, operating specifications will still govern the way a utility handles its clearances as is currently done. We do agree, however, that landowners and local regulators may want utilities to reduce operational clearance levels based on the MVCD listed in the Standard, but the utility must properly communicate the reasoning behind achieving greater clearances as per their TVMP. We do not believe that eliminating the reporting of Category 3 sustained outages will lead to less effort to mitigate danger tree exposure since all transmission outages are sensitive to a Transmission Owner and must be addressed appropriately at multiple levels within the company as well as with other regulatory agencies in some cases. Removing the qualifications requirement may initially lead to Transmission Owners employing less qualified employees and contractors but there needs to be some level of flexibility that will allow for a larger candidate pool or temporary support since individuals with specialized training are not always readily available. The Transmission Owner should be solely responsible for determining the abilities and training needs of their employees and ensure that capable individuals perform their vegetation management functions.
Hydro One Networks inc.	V2 Does not maintain or improve overall reliability	V2 will not necessarily improve reliability for the following reasons: 1) eliminating Clearance 1 will be detrimental to reliability. The determination of Clearance 1 is an important exercise for the TO to better understand the dynamics of conductor movement and vegetative growth. This required analysis should lead to development of a more informed vegetation management program. Clearance 1 also gives the TO leverage with landowners and local regulators to achieve the necessary operational clearances. If the only required clearance is the R4 Minimum Vegetation Clearance Distance (MCVD), landowners and local regulators will push the utility to maintain a clearance close to the MVCD. 2) Eliminating the reporting of Category 3 sustained outages will lead to less effort by the TOs to mitigate danger tree exposure where the TOs property rights allow. This might lead to diminished reliability.
ISO/RTO Council	V2 Does not maintain or improve overall reliability	The SRC believes the change from Reliability Coordinator to Planning Coordinator and the inclusion of specific sub 200kv facilities maintains but does not improve the reliability effectiveness of this standard over Version 1. The removal of the subrequirements R10.1 and R10.2 in Version 1 and the

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		new R10 applicable to PCs is appropriate.

18. Besides the comments you have already provided for the preceding questions, do you have further suggestions for improving this standard? If so, please elaborate.

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Salt River Project	- R4: Recommend changing the word “Minimum” in “Minimum Vegetation Clearance Distances” to “Critical” (same with M4) - Footnote #4 (page 5 of 15): Recommend adding “microburst” (after storm) - Footnote #5 (page 5 of 15): Recommend addi
Xcel Energy	(a) The comments made above regarding the Requirement Sections of FAC-003-2 would need to be followed through in the Measure Sections of the standard.(b) Compliance Section 1.5 â— 1b, the word “but” needs to be replaced with the word “which.” (c) Attachment 1 needs to be renamed “Critical Clearance Distances” as discussed above in number 4.(d) We understand the drafting team’s intent, when referring to “applicable lines”, is to encompass all 3 items under Facilities in the Applicability section. Yet it is not clear as presently worded. Please clarify this in the next draft.(e) In version 1 of FAC-003, a sustained outage caused by vegetation within the ROW likely results in a single violation. However, the latest draft of version 2 is written such that the same sustained outage would result in the violation of at least 2, if not 3, requirements. This could quickly ratchet up the penalty amount by 3-4 times. We do not feel that this is reasonable, and recommend that modifications be made to remove double or triple jeopardy circumstances.
Hydro One Networks inc.	(a) The inclusion of a detailed description of ANSI A300 contains a level of detail greater than what should be included in the standard. A simple reference to the ANSI standard would be more than sufficient to provide an example of what may be included in a TVMP, without appearing to dictate specific vegetation management practices that may or may not be available or practical for all Transmission Owners across North America.(b) In the applicability Section, Facilities (4.2.1 in the clean version) we suggest to explicitly indicate that the standard applies to BES facilities only, to read as follows:BES transmission lines (“applicable lines”) operated at 200 kV or higher, and BES transmission lines operated below 200 kV designated by the Planning Coordinator as being subject to this standard including but not limited to those that cross lands owned by federal, state, provincial, public, private, or tribal entities.
FirstEnergy Corp	1. Applicability of the standard with regard to Line Ratings - Regarding the phrase "throughout its operating range under rated conditions" in Req. R1, and also regarding the phrase "operating between no-load and their Rating" in Req. R4, R5, and R6, we feel that "rated conditions" and "Rating" is ambiguous. FE interprets the intent to reflect the maximum conductor thermal rating used in determining maximum sag conditions. We ask the SDT to confirm or clarify our interpretation. 2. Related to our comments in Question 10, section 4.2.2 should be revised to state that sub-200kV lines designated by the PC are subject to this standard 12 months after the Transmission Owner HAS RECEIVED the list from the PC.3. Changes may be needed to the Technical Ref. document based on changes to the standard per our previous comments. Also, on pg. 32 of the ref. document it shows a "high" VRF for Req. R6, but this should be "Medium". Lastly, on pg. 39 of the ref. document it references Part 11.3 which should say 1.1.3.4. Correct the misspelled word "Federal" in section 4.2.1.5. Compliance section 1.5 regarding

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	Categories, "Category 4" should be "Category 3". The footnote 7 is not needed and we suggest the team simply renumber the category list to be 1A, 1B, 2 and 3. Or, FE would support a renumbering of 1, 2, 3 and 4. The list should not skip or omit a category number.6. FE recommends that the SDT reconsider use of the term ‘applicable lines’ in the revised draft Standard. While applicability of the standard is already described, use of this term in specific requirements could suggest that there may be lines that are otherwise subject to requirements of the standard and only ‘applicable lines’ are addressed in some requirements. Therefore, we suggest removing the repeated use of the term "applicable lines" throughout the standard because it should be understood as those addressed in the "Applicability" section A4.2.. 7. Presently, the draft FAC-003-2 text includes a footnote stating that ANSI A300 standard for tree care operations is considered an industry best practice. FE recommends that this reference should not be included in the Standard. Since the ANSI standard would not provide certain obligations or requirements, it is not necessary to be included in the NERC Standard (See definition of Reliability Standard, Standards Development Procedure, p. 6). Rather, it should be included in a supporting document as a reference, as provided by the Standards Development Procedure (p. 34).
Entergy Services, Inc	A) The definition of Active Transmission Line Right of Way in the White Paper contains several examples of “inactive or unused” portions of corridors which are not contained in the definition in the standard. We suggest the examples contained in the White Paper are also included in the definition contained in the standard. Examples of something, the “corridor” in this case, helps clarify one’s understanding of “corridor”. The method is used in every dictionary. Therefore, we suggest adding the following to the definition in the standard:”Examples of inactive or unused portions of corridors include:1) The portions of the right of way acquired to accommodate future facilities. Power plant exits are examples where large rights of way are obtained for maximum corridor utilization and may currently have fewer lines constructed.2) The portion of the right of way where corridor edge zones (i.e., buffer zones) are provided for vegetation to exist.3) The portions of the right of way where double-circuit structures are installed but only one circuit is currently strung with conductors.4) Portions of the right of way with deactivated transmission lines that are unavailable for service.”B) Section 4.2 Facilities contains 3 subparts describing the facilities to which this standard applies. We suggest adding a fourth subpart from the White Paper which describes facilities to which this standard does not apply. Adding this fourth subpart will eliminate the need for future Interpretations and/or revisions to this standard. Please add to section 4.2 Facilities the following from the last paragraph of page 8 of the White Paper:”4.2.4 This standard does not apply to line sections inside the electric station or substation fence, other boundary of an electric station or substation, or underground lines.”C) The terms “imminent threat” and “vegetation imminent threat” are used in the standard. We suggest “vegetation imminent threat” be used in all locations of the standard.D) Standard R1.6 uses the term “never violated” which we believe requires 100% compliance and is too rigid a requirement given the propensity of hurricanes, tornados, and other weather conditions that cause debris to possibly broach the clearances contained in Table 1 Attachment 1. We suggest replacing “never violated” with “not violated during rated operating conditions and normal weather conditions.”E) R5, R6 and R8 contain 2 bullet items while the second bullet item in those requirements is not contained in R7. We suggest adding the second bullet item to R7:”Sustained Outages of applicable lines that result from human or animal activity.5”
MRO NERC Standards Review	A. In FAC-003-1 a self reportable violation could occur at any time vegetation was within, had previously been, or had passed through (fall in) the Clearance 2 zone. In FAC-003-2, this is reportable only if observed in real time. Under FAC-003-1, a tree

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Subcommittee	that was causing instantaneous operations of the line either through wind or loading would be a reportable violation of the Clearance 2 zone when found later during a patrol, even though the clearance now was well outside of the Clearance 2 zone. In FAC-003-2, a self reportable violation would be required only if the tree was observed, in real time, to be in the MVCD.B. Perhaps there should be a statement in FAC-003-2 that is explicit that the TO will manage its ROW to its "full and legal rights".C. The comments made above regarding the Requirement Sections of FAC-003-2 would need to be followed through in the Measure Sections of the standard.D. Compliance Section 1.5 Category 1B(“Grow-ins: Sustained Outages caused by vegetation growing into applicable lines but are not identified as an element of an IROL (or Major WECC Transfer Path) by vegetation inside and/or outside of the Active Transmission Line ROW”), the word “but” needs to be replaced with the word “which.” E. Attachment 1 needs to be renamed “Critical Clearance Distances” as discussed above in Question 4b.F. General comment to entire standard: Remove the repeated use of the term “applicable lines” throughout the revised standard. It should be understood as those addressed in the “Applicability” section A4.2.G. In version 1 of FAC-003, a sustained outage caused by vegetation within the ROW likely results in a single violation. However, the latest draft of version 2 is written such that the same sustained outage would result in the violation of at least 2, if not 3, requirements. This could quickly ratchet up the penalty amount by 3-4 times. We do not feel that this is reasonable, and recommend that modifications be made to remove double or triple jeopardy circumstances.
Utility Arborist Association	As the industry’s leading science and educational organization, the UAA urges the standards drafting team to incorporate provisions that will encourage and compel all utilities to utilize proven vegetation management techniques and practices. We advocate for adequate and appropriate training, adherence to applicable A300 standards, and a clear, consistent, science-based approach to effective vegetation management across North America. ANSI A300 has the flexibility to adjust to local conditions, so there is no reason to not require it’s implementation. We also feel that it is appropriate to expect each utility to have a qualified person on staff (or in a full or part time contracted position) who fully understands proper utlity vegetation maangment. We believe the requirements of qualified people, and adherence to best practices, should be a part of this standard. Further, it is important to recognize the impacts of not directly referencing qualifications and best management standards (A300, etc) in this standard. Now that clearance 1 (in FAC-003 version 1) has been removed, there will likely be more incidents where land agencies, local governments or individuals will attempt to force their own interpretation of what is correct on the utility. In these cases the utility should be able to point to specific references in the proposed standard which will clearly identify what needs to be done (such as the practices described in A300). The utilities should also be able to point to specific references in the standard that establish them as the true authority on the required scope of work (particularly when they are liable for any failure). A specific reference to qualified employees and adherence to A300 will enable the utilities to better control their own ROW’s and should be included in this version of FAC-003.Finally, we believe that the regulators, and other entities who shall be overseeing compliance with this standard, should have an equal understanding of utility vegetation management and compliance as the utilities charged with complying with FAC-003-02. In order to raise the understanding of vegetation managment on the part of vegetation management auditors, the UAA is developing training specifically for them. Our intent is to offer a program that will be available to utilities and compliance auditors that will lead to a consistent and informed understanding of vegetation management and its legal and regulatory requirements. Thank you for the opportunity to

Organization	Question 18 Comment
	comment on this very important regulation and the UAA stands ready to assist the standards drafting team in any way we can.
Consolidated Edison Company of New York Inc.	CECONY recommends that stricter language be used in the Standard specifically requiring the industry to remove incompatible species on Active ROWs. This should reduce the number of outages resulting from vegetation grow-ins and vegetation fall-ins and help maintain a higher level of reliability. This is currently done at the state level (in New York) and the revised wording in the Federal Standard would ensure consistency industry-wide and avoid confusion. A standard definition for the term incompatible would be required to avoid misuse of the term as well.
Edison Electric Institute	EEI has two additional recommendations for consideration by the SDT. First, the draft revised Standard stated purpose is to 'avoid vegetation related outages that could lead to Cascading.' To better align the Standard with the direction provided by Order No. 693 as well as the content of the revised draft Standard, EEI recommends that the SDT consider revising the purpose statement to read: 'To avoid vegetation-related Sustained Outages of transmission lines.'Second, EEI agrees with the intent of including events that would define exceptions for requirements to comply with FAC-003. To assist in reducing ambiguity and as an alternative to the approach in the draft Standard of using footnotes, EEI recommends that the SDT consider adding a generic exceptions statement in the applicability section more specifically stating that companies will not be subject to compliance requirements to the extent that events or circumstances beyond their control limit or prevent their abilities to perform. Here's one example:Compliance with this Standard will not apply should there exist an occurrence, non-occurrence, or other set of circumstances that are beyond the reasonable control of a Registered Entity subject to this Reliability Standard, and are not caused by the fault or negligence of the Registered Entity, including acts of God, strike, flood, drought, earthquake, storm, fire, hurricane, tornado, landslides, logging activities, animals severing trees, lightning, epidemic, war, riot, civil disturbance, sabotage, vandalism, terrorism, or action or inaction by any Governmental Authority or individual that restricts or prevents performance to comply with this Reliability Standard. Should the SDT choose to not add a specific exceptions statement, EEI encourages additional specificity in the footnotes.
Transmission Owner	FPL is in support of the changes made to the Purpose Statement. The purpose should be further clarified. FPL Suggests the following wording:To improve the reliability of applicable electric transmission facilities by preventing those vegetation related outages within active ROW that could lead to Cascading.FPL agrees with the changes in R9 and indicated that in Question 9, however, FPL sees a need for an exemption due to disasters (natural or manmade). During the hurricane seasons of 2004 and 2005 most utilities in the east and southeast were either directly or indirectly affected by the hurricanes occurring in that time period (including named storms. It was in the National interest that those not directly effected respond to requests for mutual aid from those utilities that were. Conversely, those affected had to restore their systems. Annual Work Plans were delayed or changed. An exemption or mechanism needs to be in place to allow utilities to respond with out violating the standard.
American Transmission Company	General comment to entire standard: Remove the repeated use of the term "applicable lines" throughout the revised standard. It should be understood as those addressed in the "Applicability" section A4.2.Also, ATC supports the deletion of footnote #2 to R1.1 regarding ANSI A300. Since the ANSI standard would not provide certain obligations or requirements, it is not necessary to be included in the NERC Standard. (See definition of Reliability Standard, Standards Development Procedure, p. 6) Rather,

Organization	Question 18 Comment
	it should be included in a supporting document as a reference, as provided by the Standards Development Procedure (p. 34)
Oncor Electric Delivery	Having a binary system for R4, 5, 6, 7, and 8 creates a one size fits all approach. The SDT should consider allowing for some normalizing of events / sustained outages per metric considering the number of applicable miles to allow a range of VSL's to be applied.
CenterPoint Energy	Improvements to Standard1. Revise the Purpose statement to "preventing vegetation related outages" and delete "that could lead to Cascading" since Cascading is not referenced anywhere else within the Standard.2. Within R1.6, substitute "practices" for "strategies" as a more actionable word.3. R1.2 and R3 should use the same wording when referring to the frequency of Vegetation Inspections.4. Within M1.6, substitute "practices" for "strategies" as a more actionable word.Improvements to Technical Reference 1. Revise the statement on page 9 to read as follows, "It is not intended to prevent customer outages from occurring due to tree contact with all transmission lines and voltages; however, the Standard is not intended to dissuade best utility practice regarding vegetation management for transmission lines that fall outside the Standard." The Technical Reference is a public document, and thus should be careful to mention best management practices, public safety, and hazard avoidance whenever applicable. Allowing trees to grow near transmission lines at any voltage is a public safety hazard.2. In the Wire-Border Zone section on page 15, CenterPoint Energy recommends revising this sentence as follows, "The wire zone is the section of a utility transmission right of way directly under the wires and extending outward a sufficient distance to allow for movement of the conductors", which deletes the phrase "about 10 feet on each side". The specific 10' distance is misleading where rights of way are purchased without ownership of a border zone, and it may be misleading to the public. CenterPoint Energy has not historically purchased a border zone, and the wire zone equates to the legal limits of our rights of way.The paragraphs on page 15 that start, "One way...", and "In areas where...", should be deleted because they may mislead the public by not taking into account all the needs to remove trees such as access below the lines and possible reconductoring or rebuilding of lines that change the transmission line profile and thus impact the need to remove tall trees in any instance. The prior statement that starts, "Although the wire-border zone..." is sufficient to introduce flexibility in practices.3. In the Selecting a Maintenance Strategy section on page 25, CenterPoint Energy recommends deleting the paragraph that starts, "If faced with...". It should be deleted because it may mislead the public to believing that granting exceptions for trees is a common practice and should be pursued. It does not take into account all the needs to remove trees such as access below the lines and possible reconductoring or rebuilding of lines that change the transmission line profile and thus impact the need to remove tall trees in any instance. It is also not necessary to the example.4. The third bullet under R4 on page 30 has an extra word, "Brief", that is not in the Standard itself.5. R6 quoted on page 32 has an incorrect Violation Risk Factor of "High" instead of "Medium".
Idaho Power Company	In the definition of terms remove 'intended for other facilities' from the definition for Active Transmission Line Right of Way. In the definition of Vegetation, remove ' considering the current location of the conductor and other possible locations of the conductor due to sag and sway for rated conditions' since this is covered in the Standards section.In the measures section, remove 'neighboring Planning Coordinators' from M10 since a neighbor may have different views as to which sub-200kV lines

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	are subject to Standard R10
SCE&G	N/A
WECC RC	NO
National Grid	No additional comments.
American Electric Power	No additional questions at this time.
PacifiCorp	None
NRECA - National Rural Electric Cooperative Association	NRECA on behalf of its members would like to thank the drafting team for its efforts in addressing cooperative concerns from the previous draft of FAC-003-2. In addition, it is important for the drafting team to incorporate the recommendations of the Generator Requirements at the Transmission Interface Ad Hoc Group (GOTO Team) regarding the implications of this standard for the transmission facilities designated as Generator Interconnection Facilities (GIFs). The specific recommendations NRECA supports are; the sole use of GIFs should not cause the registration of entities as Transmission Owners and Transmission Operators, clarifying requirements for GIFs, adding new requirements to make expectations clear for these facility types and working with the GOTO Team to incorporate any new definitions in the NERC Glossary of terms to clarify requirements of this standard.
Orange and Rockland Utilities, Inc.	ORU recommends that stricter language be used in the Standard specifically requiring the industry to remove incompatible species on Active ROWs. This should reduce the number of outages resulting from vegetation grow-ins and vegetation fall-ins and help maintain a higher level of reliability. This is currently done at the state level (in NY) and the revised wording in the Federal Standard would ensure consistency industry-wide and avoid confusion. A standard definition for the term incompatible would be required to avoid misuse of the term as well.
Associated Electric Cooperative, Inc.	Paragraph A.4.2.1 - Associated Electric Cooperative Inc assumes the Standard Drafting Team's intent is for the standard to apply, without exception, to all transmission lines operated at 200 kV or higher and to all transmission lines operated below 200 kV designated by the Planning Coordinator as being subject to the standard. To this end, AECI believes the list of land ownerships included in A.4.2.1 detracts from, rather than adds to, the clarity of the paragraph. It is suggested the paragraph be revised to something like, “All transmission lines (“applicable lines”) operated at 200 kV or higher, and all transmission lines operated below 200 kV designated by the Planning Coordinator as being subject to this standard.”Paragraph D.1.5 - This paragraph clearly requires Transmission Owners to provide periodic reports to the Regional Entity of Sustained Outages occurring on applicable lines that are caused by vegetation. As such, it should be included in the Requirements section of the standard. Associated Electric Cooperative Inc. does not disagree with the intent of the paragraph, only its location within the

Organization	Question 18 Comment
	standard.
Progress Energy Carolinas, Inc.	PEC recommends that the ANSI A300 footnote #2 to R1.1 be removed and included in supporting documentation (the Technical Reference document - “White Paper”).
Southern California Edison Company	SCE appreciates the great amount of time and effort expended by the Drafting Team on the FAC-003-2 Reliability Standard.
Entegra Power Group LLC	See Question 14 comments
Florida Municipal Power Agency, and its Member Cities, Lakeland Electric and Kissimmee Utility Authority	Specify an interim corrective action process for use when theTransmission Owner is temporarily constrained from performingvegetation maintenance as planned.
Vegetation Management Team	The “methods ... to control” in R1.1, the annual work plan in R1.3, and the “maintenance strategies” in R1.6 seem to refer to the same actions but require the TO to address them separately in the TVMP. This needs to be clarified or consolidated.
Central Maine Power an Energy East Company	The clearance 2 defined in FAC 003 1 was a useful tool for transmission owners to manage rights of ways to a robust standard rather than a minimum standard. This language should be included in the TVMP requirement (R1). Suggested language "The TVMP must define a clearance two". The standard would only require this distance be included as part of each T.O's plan, and would eliminate the fill in the blank concept.Suggest that standard note that qualif1ed vegetation managers are recommended to manage the V.M. program.FAC 003 2 should retain the reference to ANSI A300.
Hydro-Quebec TransEnergie (HQT)	The inclusion of a detailed description of ANSI A300 contains a level of detail greater than what should be included in the standard. A simple reference to the ANSI standard would be more than sufficient to provide an example of what may be included in a TVMP, without appearing to dictate specific vegetation management practices that may or may not be available or practical for all Transmission Owners across North America.It is recommended that stricter language be used in the Standard, specifically requiring the industry to remove incompatible species on Active ROWs. This should reduce the number of outages resulting from vegetation grow-ins and vegetation fall-ins and help maintain a higher level of reliability. This is currently done at the state level (in New York), and the revised wording in the Federal Standard would ensure consistency industry-wide and avoid confusion. A standard definition for the term incompatible would be required to avoid misuse of the term as well. Editorial comments--the “1” after “federal” in the first bullet under “Facilities” in the “Applicability” section should be a superscript to indicate the footnote. The text that a footnote refers to should appear at the bottom of the page it is used on, or at a common location, not on different pages.We reiterate the need to change the language used in the purpose of the Standard as per our answer to Q10; if not, we would appreciate to know the SDT rational.

Organization	Question 18 Comment
Independent Electricity System Operator	The inclusion of a detailed description of ANSI A300 contains a level of detail greater than what should be included in the standard. A simple reference to the ANSI standard would be more than sufficient to provide an example of what may be included in a TVMP, without appearing to dictate specific vegetation management practices that may or may not be available or practical for all Transmission Owners across North America.It is recommended that stricter language be used in the Standard, specifically requiring the industry to remove incompatible species on Active ROWs. This should reduce the number of outages resulting from vegetation grow-ins and vegetation fall-ins and help maintain a higher level of reliability. This is currently done at the state level (in New York), and the revised wording in the Federal Standard would ensure consistency industry-wide and avoid confusion. A standard definition for the term incompatible would be required to avoid misuse of the term as well. Editorial comments--the “1” after “federal” in the first bullet under “Facilities” in the “Applicability” section should be a superscript to indicate the footnote. The text that a footnote refers to should appear at the bottom of the page it is used on, or at a common location, not on different pages.
ISO New England Inc.	The inclusion of a detailed description of ANSI A300 contains a level of detail greater than what should be included in the standard. A simple reference to the ANSI standard would be more than sufficient to provide an example of what may be included in a TVMP, without appearing to dictate specific vegetation management practices that may or may not be available or practical for all Transmission Owners across North America.It is recommended that stricter language be used in the Standard, specifically requiring the industry to remove incompatible species on Active ROWs. This should reduce the number of outages resulting from vegetation grow-ins and vegetation fall-ins and help maintain a higher level of reliability. This is currently done at the state level (in New York), and the revised wording in the Federal Standard would ensure consistency industry-wide and avoid confusion. A standard definition for the term incompatible would be required to avoid misuse of the term as well. Editorial comments--the “1” after “federal” in the first bullet under “Facilities” in the “Applicability” section should be a superscript to indicate the footnote. The text that a footnote refers to should appear at the bottom of the page it is used on, or at a common location, not on different pages.
Northeast Power Coordinating Council--RSC	The inclusion of a detailed description of ANSI A300 contains a level of detail greater than what should be included in the standard. A simple reference to the ANSI standard would be more than sufficient to provide an example of what may be included in a TVMP, without appearing to dictate specific vegetation management practices that may or may not be available or practical for all Transmission Owners across North America.It is recommended that stricter language be used in the Standard, specifically requiring the industry to remove incompatible species on Active ROWs. This should reduce the number of outages resulting from vegetation grow-ins and vegetation fall-ins and help maintain a higher level of reliability. This is currently done at the state level (in New York), and the revised wording in the Federal Standard would ensure consistency industry-wide and avoid confusion. A standard definition for the term incompatible would be required to avoid misuse of the term as well. Editorial comments--the “1” after “federal” in the first bullet under “Facilities” in the “Applicability” section should be a superscript to indicate the footnote. The text that a footnote refers to should appear at the bottom of the page it is used on, or at a common location, not on different pages.

Organization	Question 18 Comment
Southern Company	The new format for the standard moves some requirements from the compliance section (i.e. outage reporting) to additional compliance information. Does this remove the outage reporting requirement from the CMEP? If not, how will it be monitored?
ReliabilityFirst Corporation	The only comment I have is in Facilities section, in the first bullet. I do not see need for adding all the verbiage (including but not limited to those that cross lands owned by federal1, state, provincial, public, private, or tribal entities) after “designated by the Planning Coordinator”.
Superintendent Transmission Maintenance	The white paper could further explain the process by which the planning coordinator and utilities identify sub-200kV lines to be included in the standard. Clarify the definition of an active transmission ROW.
Manitoba Hydro	the wording of requirement 1.5, last word should be changed from "planned" to "required" as one could change the plan based on land deal negotiations for example, or site specific engineering calculations, but at least the minimum requirements to maintain the vegetation must be met.In version 1 of FAC-003, a sustained outage caused by vegetation within the ROW likely results in a single violation. However, the latest draft of version 2 is written such that the same sustained outage would result in the violation of at least 2, if not 3, requirements. This could quickly ratchet up the penalty amount by 3-4 times. We do not feel that this is reasonable, and recommend that modifications be made to remove double or triple jeopardy circumstances.
SERC Vegetation Managment Sub-committee (VMS)	There are certain lines, not owned by Transmission Owners (TO’s) that should be covered by this standard. These include facilities owned by DP’s and GO’s that are not registered as TO’s. This should be addressed via the Standard’s applicability section and not via registration.
Bonneville Power Administration	There are several inconsistencies throughout the document regarding the way Attachments are referred to. The lines are referred to in many different ways - real-time, no load, etc. ??? Standard is a little difficult to follow. The term “sway” is not a technical term, suggest using “swing” or “blow out”.
North Carolina Electric Membership Corporation	Yes. There are certain facilities, not owned by Transmission Owners (TO’s) that should be covered by this standard. These include facilities owned by Distribution Provider’s (DP’s) and Generation Owner’s (GO’s) that are NOT registered as TO’s. In the last draft, several entities provided comments to the SDT about GO’s and DP’s who own such interconnection facilities to connect their generation and load to the transmission system. We make a plea to the SDT to reconsider those comments such as those provided by SERC Compliance Staff. As the standard currently exists today, it forces entities that have such interconnection facilities to be registered as a TO’s regardless of the length of the facility used for interconnection (50 feet, 0.50 miles or 50 miles). These additional facilities should be captured via the Standard’s applicability section and not via registration, thus making the entity subject only to the FAC-003 standard and not to all TO standards. Also, we respectfully request that the SDT provide additional guidance in the standard about length of interconnection facilities before the standard is applicable to such facilities. One suggestion has been offered in the GOTO Team forum ad we repeat here for the benefit of the SDT: Only those Generator Interconnection Facilities above 200kv which extend more than one mile from the Generator

Organization	Question 18 Comment
	Owner property boundary should be assigned applicability for FAC-003-1. A clarification may be needed to provide that those Generator Interconnection Facilities which are located entirely on Generator Owner property should not be applicable.We would also suggest the same guidance be provided for tap lines and radials owned by DPs when these taps or radial are short distances and are within DP property where there would be no gaps. Without this guidance or clarification, then it is left to each Regional Entity to apply their own opinion which may result in inconsistency in enforcing the standard.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Summary Considerations FAC-003-2
Second Industry Comment Period (9/10/09 to 10/24/09)

Background:
On January 14, 2010, the NERC Standards Committee endorsed the use of Project 2007-07 Vegetation Management as the prototype for the proof-of-concept for using the results-based criteria for developing a reliability standard. The results-based initiative is intended to focus the collective effort of NERC and industry participants on improving the clarity and quality of NERC reliability standards by developing performance, risk and competency-based requirements that accomplish a reliability objective through a defense-in-depth strategy, while eliminating documentation-driven requirements that do not have an impact on bulk power system reliability.

The Standards Committee directed the Vegetation Management SDT to stop work in refining its second draft of the Vegetation Management standard but to inform stakeholders on how the team had used stakeholder comments to refine the technical requirements carried over into draft 3 of the standard.

This report provides a copy of each of the questions that was posted for stakeholder comment with the second draft of FAC-003-2, and a summary indicating how the drafting team used stakeholder comments submitted in response to that question. The questions included in the second comment form provided explicit references to either background information provided in the comment form or to specific requirements or other elements in the standard and have been paraphrased here.

All questions asked and all comments provided by stakeholders have been posted at the following site:

http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

Index to Questions and Summary Responses:

Question 1

In response to industry comments, the Requirement for documentation of a TVMP was revised to clarify that the objective of the TVMP is to improve reliability by preventing Sustained Outages due to vegetation. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.
Second draft of proposed R1:

R1. Each Transmission Owner shall have a documented transmission vegetation management program that describes how it conducts work on its Active Transmission Line Rights of Way to prevent Sustained Outages due to vegetation, considering all possible locations the conductor may occupy under the effects of sag and sway throughout its operating range under rated conditions. The transmission vegetation management program shall: *[Violation Risk Factor – Lower][Time Horizon – Long-term planning]*

- **1.1.** Specify the methods that the Transmission Owner may use to control vegetation.[1]
- **1.2.** Specify a Vegetation Inspection frequency of at least once per calendar year that takes into account local[2] and environmental factors.
- **1.3.** Require an annual work plan. An annual work plan shall:
  - **1.3.1.** Identify the applicable lines to be maintained
  - **1.3.2.** Identify the work to be performed and methods to be used
  - **1.3.3.** Be flexible to adjust to changing conditions and to findings from Vegetation Inspections. Adjustments to the plan within the year are permissible.
  - **1.3.4.** Take into consideration permitting and scheduling requirements from landowners or regulatory authorities.
- **1.4.** Require a process or procedure for response to an imminent threat of a vegetation-related Sustained Outage. The process or procedure shall specify actions which shall include communication of the threat to the responsible control center.
- **1.5.** Specify an interim corrective action process for use when the Transmission Owner is temporarily constrained from performing vegetation maintenance as planned.
- **1.6.** Specify the maintenance strategies used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that Table 1 clearances in Attachment 1 are never violated. The maintenance strategies shall consider the sag and sway of the conductor throughout its operating range under rated conditions.

Summary Consideration: The vast majority of comments for this Question related to the Annual Vegetation Inspection frequency. Those commenters believed that a once/year mandate was too prescriptive and preferred to let the Transmission Owner choose a frequency.

[1] ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

[2] Local factors include items such as treatment cycle, extent and type of treatment, and their relationship to the normal growth rate.

After reviewing Order 693 in its entirety, the SDT set the frequency at once/year to avoid a fill-in-the-blank requirement and establish a reasonable frequency for most regions. However, the SDT also made it explicitly clear that this Vegetation Inspection can be combined with other line inspections to allow maximum flexibility in meeting this requirement. The vast majority of other comments dealt with specific wording in the Draft 2, Requirement 1. In an effort to be less prescriptive, the new Draft has removed most of the text that commenters wanted changed.

Question 2

In response to industry comments, the Requirement for implementation of Imminent Threat process/procedure was revised. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Second draft of proposed R2:

R2. Each Transmission Owner shall implement its imminent threat process or procedure when the Transmission Owner has actual knowledge of such a threat, obtained through normal operating practices. *[Violation Risk Factor – Medium][Time Horizon – Real Time]*

Summary Consideration: Ninety percent of respondents agreed with Requirement 2 (Implementation of the Imminent Threat Process). No major themes of disagreement surfaced. Two respondents expressed confusion between the NERC defined term "Operating Process" and the language "operating practices" used in R2. Two respondents preferred more specificity in the requirement for audit purposes, one respondent suggested changing "actual knowledge" to "confirmed" and one respondent expressed concerns about proving a negative. Two other respondents had comments that were more appropriate for questions 1 & 4 and are answered there.

The SDT considered all comments and essentially retained all the previous language in the new draft. Of note, the term "actual knowledge" was changed to "verified knowledge" based on the guidelines for Requirements with the new standard format. This change still retains its meaning that the Transmission Owner "confirmed" the potential threat prior to initiating the Imminent Threat process.

Proposed requirement in Draft 3 of FAC-003-2:

R5. Each Transmission Owner shall take interim corrective action when it is temporarily constrained from performing planned vegetation work, where a Transmission Line is put at potential risk due to the constraint.

Question 3

In response to industry comments, the Requirement for conducting Vegetation Inspections was revised. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Second draft of proposed R3:

R3. Each Transmission Owner shall conduct Vegetation Inspections of all applicable lines (as measured in line miles) in accordance with the frequency specified in its transmission vegetation management program, unless constrained by natural disasters. When constrained by a natural disaster, the Transmission Owner shall conduct the Vegetation Inspection(s) within six months or a period agreed to by its Regional Entity, whichever is greater. *[Violation Risk Factor – Medium][Time Horizon – Operations Planning]*

Summary Consideration: Eight commenters perceived an inconsistency in the inspection frequency required between Requirement 1.2 and Requirement R3. Eleven (11)respondents felt an inspection frequency of longer than once per calendar year should be acceptable, the required frequency for inspection was unclear, or that the requirement should simply state an inspection interval of once per calendar year. Five comments (5) noted that the Requirement R3 exception for non performance due to natural disasters should be expanded, re-organized, or re-worded to be more clear or include a number of additional situations including disease or species epidemics. Several entities (6) expressed a concern over the use of the term "line miles" in the performance measures for this requirement. Finally, a few comments (2) were received that suggested the phrase "all applicable lines" be removed from the requirement.

With this new Draft, the Standards Drafting Team has removed 1.2 which eliminates any perceived confusion. After reviewing Order 693 in its entirety, the SDT re-established the frequency at once/year to avoid a fill-in-the-blank requirement and establish a reasonable frequency for most regions. However, the SDT also made it explicitly clear that this Vegetation Inspection can be combined with other line inspections to allow maximum flexibility in meeting this requirement. The FAC-003-2 Draft 3 includes a general, and more inclusive, Force Majeure section which applies to the entire Standard. The Standards Drafting Team responded to industry comments about the term "line miles". There is now more explanation of this term in the VSL for R6."

Question 4

In response to industry comments, the Requirement for preventing vegetation encroachments was revised. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Second draft of proposed R4:

R4. Each Transmission Owner shall prevent encroachment of vegetation into the Minimum Vegetation Clearance Distances (MVCD) listed in FAC-003-2 - Attachment 1 for its applicable lines as observed in real-time operating between no-load and their Rating, with the following exceptions: *[Violation Risk Factor – Medium][Time Horizon – Real Time]*

- Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from natural disasters.[3]
- Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from human or animal activity.[4]
- Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from falling vegetation.

Summary Consideration: Fifty-two percent (32 of 62) of the respondents disagreed with various aspects of Requirement 4 (Preventing Vegetation Encroachments). A major theme from 19 responses requested clarification on the fall-in tree exemption particularly when a fall-in tree may be lodged in another tree. The following six minor themes were identified:

- Requested the use of the word “critical” rather than “minimum” to aide with public perception (7 responses)
- Clarification on operating beyond emergency ratings (7 responses)
- Clarification on what is meant by “observed in real-time”(6 responses)
- Requested a force majeure exemption be added (5 responses)
- Requested observations be done by qualified observers (4 responses)
- Requested to eliminate R4 (4 responses).
- Requested an interpolation in the clearance tables for altitude(2 responses)
- Identified “Double Jeopardy” concern between Requirement 4 and the outage Requirements(1 response)

The SDT considered all comments and determined that two of these were significant enough to change the standard - the SDT combined the outage requirements (R5, R6, R7 and R8) with the encroachment requirement (R4). The SDT determined the other comments could be adequately addressed as modifications for clarity to the Technical Reference Document.

[3] Examples include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods.

[4] Examples include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation.

Question 5

In response to industry comments, the Requirement for preventing Sustained Outages due to grow-ins on IROL or Major WECC Transfer Paths was developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Second draft of proposed R5:

R5. Each Transmission Owner shall prevent Sustained Outages[5] of applicable lines that are identified as an element of an Interconnection Reliability Operating Limit (IROL) (or Major WECC Transfer Path) due to vegetation growing into a conductor operating between no-load and its Rating, with the following exceptions: *[Violation Risk Factor – High][Time Horizon – Real Time]*

- Sustained Outages of applicable lines that result from natural disasters.
- Sustained Outages of applicable lines that result from human or animal activity.

Summary Consideration: Commenters generally agreed with R5 in draft 2. The most significant issues that the SDT needed to consider were: the addition of other exclusionary conditions, the prima facie double jeopardy that exists with this requirement and R4, the lack of robust VSLs, and the need for further clarity on terms and concepts (e.g. rating, minimum).

Finally, a few commenters noted that this requirement is structured unlike other conventional NERC standard requirements in that it does not say what must be accomplished for reliability (and compliance) but rather says what must NOT be done.

The SDT considered these comments and determined that two of these were significant enough to change the standard - the SDT combined the outage requirements (R5, R6, R7 and R8) with the encroachment requirement (R4), with one combined Requirement for IROLs/Major WECC Transfer Paths and another combined Requirement for all other lines. A broadened Force Majeure section was added to the applicability section of the standard. Additionally, the new R1 and R2 in this Draft were reworded to describe what must be done.

[5] Multiple Sustained Outages on an individual line, if caused by the same vegetation, shall be considered as one outage regardless of the actual number of outages within a 24-hour period.

Question 6

In response to industry comments, the Requirement for preventing Sustained Outages due to grow-ins on non-IROL or Major WECC Transfer Paths was developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Second draft of proposed R6:

R6. Each Transmission Owner shall prevent Sustained Outages of applicable lines that are not an element of an IROL (or major WECC Transfer Path) due to vegetation growing into a conductor operating between no-load and its Rating, with the following exceptions: *[Violation Risk Factor – Medium][Time Horizon – Real Time]*

- Sustained Outages of applicable lines that result from natural disasters.
- Sustained Outages of applicable lines that result from human or animal activity.

Summary Consideration: Commenters generally agreed with R6 in draft 2. The most significant issues that the SDT needed to consider were: the addition of other exclusionary conditions, the prima facie double jeopardy that exists with this requirement and R4, the lack of robust VSLs, and the need for further clarity on terms and concepts (e.g. rating, minimum).

Finally, a few commenters noted that this requirement is structured unlike other conventional NERC standard requirements in that it does not say what must be accomplished for reliability (and compliance) but rather says what must NOT be done.

The SDT considered these comments and determined that two of these were significant enough to change the standard and have combined the outage requirements (R5, R6, R7 and R8) with this encroachment requirement (R4), with one combined Requirement for IROLs/Major WECC Transfer Paths and another combined Requirement for all other lines. A broadened Force Majeure section was added to the applicability section of the standard. Additionally, the new R1 and R2 in this Draft were reworded to describe what must be done.

Question 7

In response to industry comments, the Requirement for preventing Sustained Outages due to blowing together of vegetation and transmission line conductors was developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Second draft of proposed R7:

R7. Each Transmission Owner shall prevent Sustained Outages of applicable lines due to the blowing together of vegetation and a conductor within an Active Transmission Line Right of Way (operating within design blow-out conditions) with the following exception: *[Violation Risk Factor – Medium][Time Horizon – Real Time]*

- Sustained Outages of applicable lines that result from natural disasters or wind-blown debris.

Summary Consideration: Approximately 70% of the respondents agreed with Requirement R7. Among the commenters who disagreed, a major comment issue pertains to the definition of the Active Transmission Line ROW which is further split into two sub issues.

- The first sub issue relates to a desire for a more descriptive definition of Active ROW.
- The other sub issue suggests the elimination of Active ROW.

A minority comment area pertains to altering the requirement to become more performance based with a graduated set of VSLs.

The SDT believes that the definition of "active transmission right-of-way" is appropriate for meeting the objectives of the Standard. This topic is addressed in the ***Guideline and Technical Basis*** section of this of FAC-003-2 Draft 3. The SDT considered the other comments and determined that two of these were significant enough to change the standard - the SDT combined the outage requirements (R5, R6, R7 and R8) with this encroachment requirement (R4), with one combined Requirement for IROLs/Major WECC Transfer Paths and another combined Requirement for all other lines. A broadened Force Majeure section was added to the applicability section of the standard. Additionally, the new R1 and R2 in this Draft were reworded to describe what must be done.

Question 8

In response to industry comments, the Requirement for preventing Sustained Outages due to fall-ins of vegetation was developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Second draft of proposed R8:

R8. Each Transmission Owner shall prevent Sustained Outages of applicable lines due to vegetation falling into a conductor from within an Active Transmission Line Right of Way with the following exceptions: *[Violation Risk Factor – Medium] [Time Horizon – Real Time]*

- Sustained Outages of applicable lines that result from natural disasters or wind-blown debris.
- Sustained Outages of applicable lines that result from human or animal activity.

Summary Consideration: Approximately 78% of the respondents agreed with the Requirement R8. Among the commenters who disagree, a major comment pertains to the definition of Active Transmission Line ROW which is further split up into two sub issues.

- The first sub issue relates to a desire for a more descriptive/quantitative definition of the Active Transmission Line ROW.
- The other sub issue suggests the elimination of Active Transmission Line ROW.

A minority comment area pertains to altering the requirement to become more performance based with a graduated set of VSL's.

The SDT believes that the definition of "active transmission right-of-way" is appropriate for meeting the objectives of the Standard. This topic is addressed in the ***Guideline and Technical Basis*** section of FAC-003-2 Draft 3. The SDT considered the other comments and determined that two of these were significant enough to change the standard and have combined the outage requirements (R5, R6, R7 and R8) with this encroachment requirement (R4), with one combined Requirement for IROLs/Major WECC Transfer Paths and another combined Requirement for all other lines. A broadened Force Majeure section was added to the applicability section of the standard. Additionally, the new R1 and R2 in this Draft were reworded to describe what must be done.

Question 9

In response to industry comments, the Requirement for implementation of annual work plan was developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Second draft of proposed R9:

R9. Each Transmission Owner shall implement its annual work plan for vegetation management to accomplish the purpose of this standard. *[Violation Risk Factor – Medium] [Time Horizon – Operations Planning]*

Summary Consideration: A majority of commenters requested the restoration of the phrase "subject to legal rights," citing that doing so would improve the ability of TO's in expediting approvals for access. A few comments objected to the phrase "to accomplish the purpose of the standard" citing it was superfluous. A minority of comments pertained to the extent and effect of the phrase "within the year". Commenters pointed out that carryover work into the next year is not possible with the requirement 1.3 as written.

In response to overwhelming industry comments from the first posting of the draft standard, the SDT removed the words "within the extent of its easements and/or legal rights". The concern expressed by the first commenters pertained to avoiding the situation where the expectation is for the transmission Owner to exercise its fullest legal rights when not needed. The SDT did remove the two phrases for clarity and in keeping with the guidelines for this new form of standard development. And sections 1.3.3 and 1.3.4 which were subject to misinterpretation have been removed.

Question 10

In response to industry comments, the Requirement for the preparation of list for sub 200kV transmission lines by the Planning Coordinator was developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Second draft of proposed R10:

R10. Each Planning Coordinator shall prepare and review annually, a list of lines that are operated below 200kV, if any, which are subject to this standard. Each Planning Coordinator shall consult with its Transmission Owner(s) and neighboring Planning Coordinators to obtain input to develop the list. *[Violation Risk Factor – Lower] [Time Horizon – Long-term Planning]*

Summary Consideration: An overwhelming majority of respondents agreed with this requirement as found in the second draft. For those commenters that disagreed with the requirement, three concepts arose. First, some commenters note that a similar identification of important circuit exists in FAC-014 and as such this requirement is unnecessary. The second issue expressed involves the interaction between the TO and the PC. There was concern that the word “consult” was ambiguous and that the mere preparation of the list did not ensure that the TO would be provided the list. The last group opined that this requirement for the actual preparation of the list could be combined with the requirement to establish a methodology (R11) since either one is toothless without the other.

After reviewing these comments as well as a complete analysis of Draft 2 with respect to the guidelines for this new results-based standard development process, the Requirements dealing with the Planning Coordinator have been removed. For sub-200 kV lines, the applicability will derive from identification of Transmission Lines associated with IROLs or as Major WECC Transfer Paths - analysis already exists for both of these.

Question 11

In response to industry comments, the Requirement for the Planning Coordinator to document method for identification of applicable sub-200kV transmission lines was developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Second draft of proposed R11:

R11. Each Planning Coordinator shall develop and document its method for assessing the reliability significance of sub-200kV transmission lines whose loss would place the grid at an unacceptable risk of instability, separation, or cascading failures. *[Violation Risk Factor – Lower] [Time Horizon – Long-term Planning]*

Summary Consideration: An overwhelming majority of respondents agreed with this requirement as found in the second draft. For those commenters that disagreed with the requirement the most common concern was that a similar identification of important circuit exists in FAC-014 and as such this requirement is unnecessary or duplicative. Two minor opinions also arose, one that all lines should be included in this standard, regardless of voltage, the other that no lines operating at voltage less than 200kV should be included.

After reviewing these comments as well as a complete analysis of Draft 2 with respect to the guidelines for this new results-based standard development process, the Requirements dealing with the Planning Coordinator have been removed. For sub-200 kV lines, the applicability will derive from identification of Transmission Lines associated with IROLs or as Major WECC Transfer Paths - analysis already exists for both of these.

Question 12

The SDT received suggestions from commenters to re-sequence the requirements contained in the standard to improve the logical flow of this document. The SDT submits for consideration a proposed alternative sequence. Do you agree with the proposed alternative sequencing? If not, please recommend a suggested sequence.

Summary Consideration: With only one exception, every commenter agreed that some re-sequencing was logical and appropriate. All others that disagreed with the SDT proposal included alternative sequences.

The SDT has rewritten the Requirements and re-sequenced those remaining by Results-based -type requirements, i.e., competency-based, risk-based, or performance-based.

Question 13
The Implementation Plan proposes an effective date that gives entities at least a year to become fully compliant. Do you agree with this implementation plan? If not, please indicate what should be changed and indicate why.

Summary Consideration: Most commenters felt that the proposed implementation was acceptable. However, a sizable number found this proposed Revision to be far superior to the current in-force standard and would like the SDT to consider options to expedite the implementation. One commenter indicated they would need more time.

The SDT has chosen to retain the implementation plan, rather than attempt an expedited schedule, with FAC-003-2 Draft 3.

Question 14

Do you have further questions about the standard that the Technical Reference document (White Paper) does not clear up? If so, please elaborate and propose additions.

Summary Consideration: The most prevalent comment requested revisions to the Diagrams to eliminate trees in impermissible areas. Another popular comment dealt with a change to the Active Transmission Line Right of Way. Some commenters wanted the SDT to address the Generator Interconnection Facility (GIF) issue. And finally, a few commenters wanted a change in the phrase “operating range” and in an expanded Force Majeure section.

The SDT will modify the Drawings as requested and they will be provided in the Technical Reference Document which is planned to be posted on March 23rd 2010.

The SDT slightly modified the definition of Active Transmission Line Right of Way as shown:

Active Transmission Line Right of Way — A strip or corridor of land that is occupied by active Transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities.

The SDT is aware of the GIF issue, i.e. 200 kV, and above, circuits owned by Generator Owners which have in some instances been considered Transmission Lines. NERC created a team to address this issue for all NERC standards. The product of that team was a report of suggested changes that will be addressed by a NERC drafting team. As such this draft of FAC-003 does not include any of those recommendations as they may apply to this standard.

The phrase “operating range” has been re-written to use all NERC terms and a general Force Majeure section has been added to the applicability section of the standard.

Question 15

In response to industry comments, the applicability section is revised to replace Reliability Coordinator with Planning Coordinator. Do you agree with these changes? If not, please explain and propose an alternative.

Summary Consideration: The vast majority of commenters agreed the Planning Coordinator was the appropriate entity. A common concern of those who disagreed was that the Planning Coordinator role is not defined, not well defined, or duplicated in practice. (The SDT believes that this is registration/Functional Model problem not suited for resolution in this standard.) Only one commenter suggested the Reliability Coordinator was more appropriate for technical reasons, opining that the Reliability Coordinator was better suited to determine the importance of lines.

After reviewing these comments as well as a complete analysis of Draft 2 with respect to the guidelines for this new results-based standard development process, the Requirements dealing with the Planning Coordinator have been removed. For sub-200 kV lines, the applicability will derive from identification of Transmission Lines associated with IROLs or as Major WECC Transfer Paths - analysis already exists for both of these.

Question 16

In response to industry comments, changes were made to the definitions. Do you agree with these changes? If not, please explain and propose an alternative.
Definitions proposed with FAC-003-2 Draft 2:

> **Active Transmission Line Right of Way** — A strip of land that is occupied by active transmission facilities. This corridor does not include the inactive or unused part of the Right of Way intended for other facilities.
>
> **Vegetation Inspection** — The systematic examination of vegetation conditions on an Active Transmission Line Right of Way. This inspection may be combined with a general line inspection. The inspection includes the documentation of any vegetation that may pose a threat to reliability prior to the next planned inspection or maintenance work, considering the current location of the conductor and other possible locations of the conductor due to sag and sway for rated conditions.

Summary Consideration: A majority of commenters expressed a concern with the Active Transmission Line ROW definition ranging from unnecessary to requiring modification. Those who recommended modification cited an issue with the phrase "intended for other facilities". The belief is this phrase might preclude certain parts of a ROW from being considered inactive. A minority comment pertains to the concern of abuse in the application of the concept of Active Transmission Line ROW.

The SDT has revised the definition to attempt to address some of the concerns and in keeping with the guidelines for this new results-based standard development process.

> **Active Transmission Line Right-of-Way**
> A strip or corridor of land that is occupied by active transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities.

The majority of commenters held concern with two aspects of Vegetation Inspection definition. One concern relates to the phrase "poses a threat" and offered the alternative phrase "poses an unacceptable risk" in its place. The other concern questions the necessity of the last sentence of the definition which contains "requirement-like" text about documentation. The SDT changed the definition as shown below:

> **Vegetation Inspection**
> The systematic examination of vegetation conditions on an Active Transmission Line Right-of-Way and may be combined with a general line inspection.

Question 17

When compared to Version 1, does this proposed Version 2 of the standard either maintain or improve overall electric reliability? Please provide a technical basis for your response?

Summary Consideration: The majority of the commenters agreed that Draft 2 improved reliability. Of those who disagreed, the primary objection was the elimination of Clearance 1 and removal of the qualification requirement. The commenters cited a reduce leverage with landowners in the rationale for disagreement. A majority comment insists that the standard ought to require the application of best management practices. A majority comment insists that the standard ought to require the application of best management practices.

The SDT thanks the commenters for their support. With this new Draft, the essential concepts in Draft 2 are retained with wording better suited to the new Results-based standards development process. The SDT believes that the qualification issue is better left to a SAR team for PER standards. The SDT considered requiring ANSI A300 as part of this standard but opted to include it in the ***Guideline and Technical Basis*** section.

Question 18

Besides the comments you have already provided for the preceding questions, do you have further suggestions for improving this standard? If so, please elaborate.

Summary Consideration: Many commenters repeated concerns expressed in other sections. The most cited items were: the purpose statement, the definition of applicable lines, double jeopardy for encroachments and outages, the GO/GOP/DP line issue, the necessity for a general force majeure statement, and the reference to ANSI A300.

The SDT has replaced the purpose statement with an Objective statement retaining the same concept.

The Applicability section has been revised to address commenters concerns, except relating to Generator Interconnection Facilities. (Please see response to Question 14.)

The Double Jeopardy concerns were addressed by combining requirements to produce the new Draft R1 and R2.

A general Force Majeure section was added to the applicability section of the standard that covers all Requirements. The reference to ANSI 300 has been added to the ***Guideline and Technical Basis*** section.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SC approved SAR for initial posting (January 11, 2007).
2. SAR posted for comment (January 15–February 14, 2007).
3. SAR posted for comment (April 10–May 9, 2007).
4. SC authorized moving the SAR forward to standard development (June 27, 2007).

Proposed Action Plan and Description of Current Draft
This is the first posting of the proposed revisions to the standard in accordance with Results-Based Criteria. The drafting team requests posting for a 30-day informal comment period.

Future Development Plan

Anticipated Actions	Anticipated Date
Drafting team considers comments, makes conforming changes, posts for 30-day informal comment period.	April 2010
Drafting team considers comments, makes conforming changes, and requests SC approval to proceed to formal comment and ballot.	June 2010
Recirculation ballot of standards.	August 2010
Receive BOT approval	September 2010

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Active Transmission Line Right-of-Way
A strip or corridor of land that is occupied by active transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities.

Examples of active portions of corridors include:
The width of any Active Transmission Line Right-of-Way (ROW) is the portion of the ROW that has been cleared of vegetation to meet design clearance requirements such as National Electrical Safety Code or other design criteria, for the reliable operation of active facilities.

Examples of inactive portions of corridors include:

1) The portions of the ROW acquired to accommodate future Facilities. Power plant exits are examples where large ROWs are obtained for maximum corridor utilization and may currently have fewer circuits constructed.
2) The portion of the ROW where corridor edge zones are designated by regulatory bodies for vegetation to exist.
3) The portions of the ROW where double-circuit structures are installed but only one circuit is currently strung with conductors.

Vegetation Inspection
The systematic examination of vegetation conditions on an Active Transmission Line Right-of-Way which may be combined with a general line inspection.

The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.

Current definition of Vegetation Inspection: The systematic examination of a transmission corridor to document vegetation conditions.

Effective Dates

Requirement	Jurisdiction									
	Alberta	**British Columbia**	**Manitoba**	**New Brunswick**	**Newfound-land**	**Nova Scotia**	**Ontario**	**Quebec**	**Saskatch-ewan**	**USA**
R1	**1**	**1**	**1**	**3**	TBD	TBD	**2**	TBD	**1**	**1**
R2	**1**	**1**	**1**	**3**	TBD	TBD	**2**	TBD	**1**	**1**
R3	**1**	**1**	**1**	**3**	TBD	TBD	**2**	TBD	**1**	**1**
R4	**1**	**1**	**1**	**3**	TBD	TBD	**2**	TBD	**1**	**1**
R5	**1**	**1**	**1**	**3**	TBD	TBD	**2**	TBD	**1**	**1**
R6	**1**	**1**	**1**	**3**	TBD	TBD	**2**	TBD	**1**	**1**
R7	**1**	**1**	**1**	**3**	TBD	TBD	**2**	TBD	**1**	**1**

1. First calendar day of the first calendar quarter one year after applicable regulatory authority approval for all requirements
2. First calendar day of the first calendar quarter one year following Board of Trustees adoption unless governmental authority withholds approval
3. First calendar day of the first calendar quarter that is at least one year following Board of Trustees adoption

Exceptions:

Lines operated below 200kV, designated by the Planning Coordinator as an element of an IROL or as a Major WECC transfer path, become subject to this standard 12 months after the date the Planning Coordinator or WECC initially designates the lines as being subject to this standard.

An existing transmission line operated at 200kV or higher that is newly acquired by an asset owner and was not previously subject to this standard, becomes subject to this standard 12 months after the acquisition date of the line(s).

Version History

Version	Date	Action	Change Tracking
1	TBA	1. Added “Standard Development Roadmap.” 2. Changed “60” to “Sixty” in section A, 5.2. 3. Added “Proposed Effective Date: April 7, 2006” to footer. 4. Added “Draft 3: November 17, 2005” to footer.	01/20/06
1	April 4, 2007	Regulatory Approval — Effective Date	New
2			

Introduction

1. **Title:** Transmission Vegetation Management

2. **Number:** FAC-003-2

3. **Objectives:** To improve the reliability of the electric Transmission system by preventing those vegetation related outages that could lead to Cascading.

4. **Applicability**

 4.1. Functional Entities:

  4.1.1 Transmission Owners

 4.2. Facilities: Defined below, including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities:

  4.2.1. Overhead transmission lines operated at 200kV or higher.

  4.2.2. Overhead transmission lines operated below 200kV having been identified as elements of an Interconnection Reliability Operating Limit (IROL).

  4.2.3. Overhead transmission lines operated below 200 kV having been identified as included in the definition of one of the *Major WECC Transfer Paths in the Bulk Electric System*.

  4.2.4. This Standard does not apply to Facilities identified above (4.2.1 through 4.2.3) located in the fenced area of a switchyard, station or substation.

 4.3. Other:

  4.3.1. This Standard does not apply to any occurrence, non-occurrence, or other set of circumstances that are beyond the reasonable control of a Transmission Owner subject to this Reliability Standard, and are not caused by the fault or negligence of the Transmission Owner, including acts of God, flood, drought, earthquake, major storms, fire, hurricane, tornado, landslides, logging activities, animals severing trees, lightning, epidemic, strike, war, riot, civil disturbance, sabotage, vandalism, terrorism, wind shear, or fresh gales that restricts or prevents performance to comply with this reliability standard's requirements.

5. **Background**

This NERC Vegetation Management Standard ("Standard") uses a defense-in-depth approach to improve the reliability of the electric Transmission System by preventing those vegetation related outages that could lead to Cascading. This Standard is not intended to address non-preventable outages such as those due to vegetation fall-ins from outside the Active Transmission Line Right-of-Way, vandalism, human errors

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies"*.

and acts of nature. Operating experience indicates that trees that have grown out of specification have contributed to Cascading, especially under heavy electrical loading conditions.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the Standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the Standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.

This Standard addresses vegetation management along applicable overhead lines that serve to connect one electric station to another. However, this Standard does not apply to underground lines or to line sections inside an electric station boundary.

This Standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this Standard is not written to address such isolated situations which have little impact on the overall Bulk Electric System.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of multiple line failures and Cascading. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are statistically intermittent. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this Standard’s emphasis is on vegetation grow-ins.

Requirements and Measures

R1. Each Transmission Owner shall prevent vegetation from encroaching within the Minimum Vegetation Clearance Distance (MVCD) of each line conductor that is identified as an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions) to avoid a Sustained Outage.

Rationale
The MVCD is a calculated minimum distance stated in feet (meters) to prevent spark-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method.

M1. Evidence of violation of Requirement R1 is limited to**:**

- Real-time observation of encroachment into the MVCD, or
- A vegetation-related Sustained Outage due to a fall-in from inside the Active Transmission Line ROW, or
- A vegetation-related Sustained Outage due to blowing together of applicable lines and vegetation located inside the Active Transmission Line ROW, or
- A vegetation-related Sustained Outage due to a grow-in.

Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

R2. Each Transmission Owner shall prevent vegetation from encroaching within the MVCD of each applicable line conductor, which are not elements of an IROL and are not a Major WECC transfer path, (operating within Rating and Rated Electrical Operating Conditions) to avoid a Sustained Outage.

Rationale
The MVCD is a calculated minimum distance stated in feet (meters) to prevent spark-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven Transmission design method.

M2. Evidence of violation of Requirement R2 is limited to**:**

- Real-time observation of encroachment into the MVCD, or
- A vegetation-related Sustained Outage due to a fall-in from inside the Active Transmission Line ROW, or
- A vegetation-related Sustained Outage due to blowing together of applicable lines and vegetation located inside the Active Transmission Line ROW, or
- A vegetation-related Sustained Outage due to a grow-in.

Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

R3. Each Transmission Owner shall have a documented transmission vegetation management program that describes how it conducts work on its Active Transmission Line ROWs to avoid Sustained Outages due to vegetation, considering all possible locations the conductor may occupy assuming operation within Rating and Rated Electrical Operating Conditions.

M3. Each Transmission Owner has a documented transmission vegetation management program that describes how it conducts work on its Active Transmission Line ROW to avoid Sustained Outages due to vegetation, considering all possible locations the conductor may occupy assuming operation within Rating and Rated Electrical Operating Conditions.

Rationale

Provide a basis for evaluation on the intent and competency of the Transmission Owner in maintaining vegetation. There may be many acceptable approaches to maintain clearances. However, the Transmission Owner should be able to state what its approach is and how it conducts work to maintain clearances. See Figure 1 for an illustration of possible conductor locations.

R4. Each Transmission Owner shall notify the responsible control center when it has verified knowledge of a vegetation imminent threat condition. A vegetation imminent threat condition is one which is likely to cause a Sustained Outage at any moment.

M4. Each Transmission Owner that has experienced a verified vegetation imminent threat will have evidence that it notified the responsible control center.

Rationale

To ensure rapid notification of the correct personnel when an occurrence of a critical situation is observed. Verified knowledge includes observations by journeyman lineman, utility arborist, or other qualified personnel, or a report verified by these personnel.

R5. Each Transmission Owner shall take interim corrective action when it is temporarily constrained from performing planned vegetation work, where a transmission line is put at potential risk due to the constraint.

M5. Each Transmission Owner has evidence of the interim corrective action taken for each temporary constraint where a transmission line was put at potential risk. Examples of acceptable forms of evidence may include work orders, invoices, or inspection records.

Rationale

Legal actions and other events may occur which result in constraints that prevent the Transmission Owner from performing planned vegetation maintenance work. When this event occurs and the work is essential to avoid risk to the transmission line the Transmission Owner must establish and act on a plan to prevent an imminent threat. This is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

R6. Each Transmission Owner shall perform a Vegetation Inspection of all applicable transmission lines at least once per calendar year.

M6. Each Transmission Owner has evidence that it conducted Vegetation Inspections at least once per calendar year for applicable transmission lines. Examples of acceptable forms of evidence may include work orders, invoices, or inspection records.

Rationale

The requirement is for once per calendar year because that seems to be reasonable length of time for a majority of situations. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections that may affect reliability.

R7. Each Transmission Owner shall execute a flexible annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD.

M7. Each Transmission Owner has evidence that it executed a flexible annual vegetation work plan. Examples of acceptable forms of evidence may include work orders, invoices, or inspection records.

Rationale

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. A flexible annual vegetation work plan allows for work to be deferred into the following calendar year provided it does not have the potential to become an imminent threat.

Compliance

Compliance Enforcement Authority

- Regional Entity

Compliance Monitoring and Enforcement Processes:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

Evidence Retention

The Transmission Owner retains data or evidence of Requirements R1 through R7, Measures M1 through M7 for three years to show compliance unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

Additional Compliance Information
(See Administrative Procedure)

Time Horizons, Violation Risk Factors, and Violation Severity Levels

Table 1

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High	The Transmission Owner failed to prevent vegetation from encroaching within the MVCD of a transmission line as described in R1.	The Transmission Owner incurred a Sustained Outage due to vegetation falling into a transmission line as described in R1 from within the Active Transmission Line ROW.	The Transmission Owner incurred a Sustained Outage due to the blowing together of vegetation and a transmission line as described in R1 from within the Active Transmission Line ROW.	The Transmission Owner incurred a Sustained Outage due to vegetation growing into a transmission line as described in R1.
R2	Real-time	Medium	The Transmission Owner failed to prevent vegetation from encroaching within the MVCD of a transmission line as described in R2.	The Transmission Owner incurred a Sustained Outage due to vegetation falling into a transmission line as described in R2 from within the Active Transmission Line ROW.	The Transmission Owner incurred a Sustained Outage due to the blowing together of vegetation and a transmission line as described in R2 from within the Active Transmission Line ROW.	The Transmission Owner incurred a Sustained Outage due to vegetation growing into a transmission line as described in R2.
R3	Long-Term Planning	Lower		The Transmission Owner has a documented transmission vegetation management program, but the transmission vegetation management program does not describe how work is conducted on the Active Transmission Line ROWs to avoid Sustained Outages due to vegetation.	The Transmission Owner has a documented transmission vegetation management program, but the transmission vegetation management program does not consider all possible locations the conductor may occupy assuming operation within Rating and Rated Electrical Operating Conditions	The Transmission Owner does not have a documented transmission vegetation management program.

R4	Real-time	Medium				The Transmission Owner had verified knowledge of a vegetation imminent threat condition and did not notify the responsible control center.
R5	Operations Planning	Medium				The Transmission Owner did not take interim corrective action when it was temporarily constrained from performing planned vegetation work where an applicable transmission line was put at potential risk.
R6	Operations Planning	High	The Transmission Owner inspected greater than 95% but less than 100% of the ROW as measured by applicable-line miles (kilometers) (based on units of choice: circuit, pole line, ROW, etc.).	The Transmission Owner inspected greater than 90% but less than or equal to 95% of the ROW as measured by applicable-line miles (kilometers) (based on units of choice: circuit, pole line, ROW, etc.).	The Transmission Owner inspected greater than 85% but less than or equal to 90% of the ROW as measured by applicable-line miles (kilometers) (based on units of choice: circuit, pole line, ROW, etc.).	The Transmission Owner inspected less than or equal to 85% of the ROW as measured by applicable-line miles (kilometers) (based on units of choice: circuit, pole line, ROW, etc.).
R7	Operations Planning	High	The Transmission Owner executed greater than 95% but less than 100% of its annual work plan as adjusted.	The Transmission Owner executed greater than 90% but less than or equal to 95% of its annual work plan as adjusted.	The Transmission Owner executed greater than 85% but less than or equal to 90% of its annual work plan as adjusted.	The Transmission Owner executed less than or equal to 85% of its annual work plan as adjusted.

Administrative Procedure

The Transmission Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of transmission lines determined by the Transmission Owner to have been caused by vegetation that includes, as a minimum, the following:.

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable transmission lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the Active Transmission Line ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable transmission lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the Active Transmission Line ROW;
- Category 2 — Fall-ins: Sustained Outages caused by vegetation falling into applicable transmission lines from within the Active Transmission Line ROW;
- Category[2] 4 — Blowing together: Sustained Outages caused by vegetation and applicable transmission lines blowing together from within the Active Transmission Line ROW.

The Regional Entity will report the outage information provided by Transmission Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Variances

None.

Interpretations

None.

[2] Category 3 reporting is eliminated.

Guideline and Technical Basis

Requirements R1 and R2:
Requirements R1 and R2 state that if a Transmission Owner observes vegetation within the distances prescribed in FAC-003 - Table 2 it is in violation of this Standard. The MVCD table contains the distances which are required to ensure that spark-over will not occur; the distances are based on the Gallet equations. Requirements R1 and R2 refer to observation in “real time”. This means an actual field observation or measurement of the conductor-to-vegetation distance and not a calculated determination of relative positions.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will help prevent transmission outages. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below.

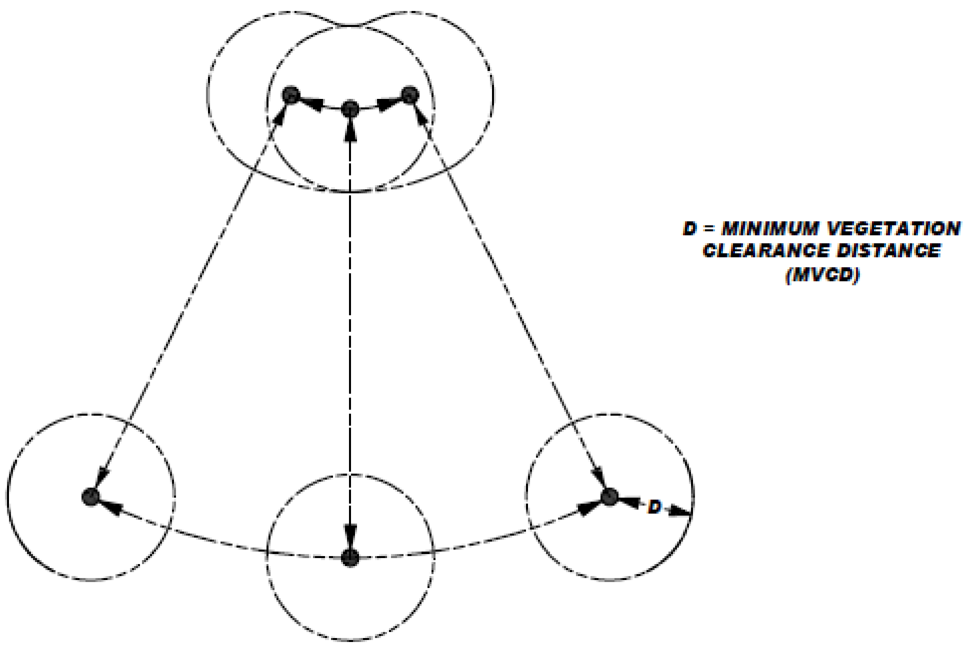

Figure 1
Cross-section view of a single conductor at a given point along the span showing six possible conductor positions due to movement resulting from thermal and mechanical loading.

By complying with encroachment-prevention Requirements R1 and R2, together with the competency-based Requirement R3 (for a documented transmission vegetation management program), the Transmission Owner will have a cohesive vegetation management program for managing vegetation in such a manner as to maintain separation between conductors and vegetation. Additionally, an effective imminent threat process and interim corrective action plan strategies should be executed to be successful in meeting these requirements. The Transmission Owner’s maintenance approach should result in vegetation never approaching the distances listed in the MVCD Table. However, brief encroachments by falling vegetation are not considered to be a violation.

In addition, the Transmission Owner should maintain detailed records of the findings of its planned inspections. This documentation constitutes evidence that the Transmission Owner had no encroachments into the MVCD Table distances.

These requirements assume that transmission lines are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its rating (potentially in violation of other standards), the occurrence of a clearance encroachment is not be a violation of this Standard. Conductor position, and the associated vegetation distance, that result from operation of a transmission line beyond its Rating (for example emergency actions taken by a TOP or RC to protect an Interconnection) is beyond the scope of this Standard.

Requirement R3:
An adequate transmission vegetation management program formally establishes the guidelines that are used by the Transmission Owner to plan and perform vegetation work that is necessary to prevent transmission outages and minimize risk to the Transmission System.

There may be many acceptable approaches to maintain clearances. However, the Transmission Owner should be able to state what its approach is and how it conducts work to maintain clearances. See Figure 1 for illustration of possible conductor locations.

Requirement R4:
The term "verified knowledge" implies reliable confirmation that an imminent threat actually exists due to vegetation. Verification could be that the initial call-in came from a trained employee able to identify such a threat or it could be verified by sending out such a trained person to confirm a call-in from a citizen.

Two key elements of an acceptable imminent threat procedure are outlined below:

- Specify the vegetation-related conditions that warrant a response:

  Examples of these vegetation-related conditions include vegetation that is near or encroaching into the MVCD (growth issue) or vegetation that presents an imminent danger of falling into the transmission conductor (fall-in issue)

- Notify the appropriate operating authority:

  The Transmission Owner has the responsibility to ensure the proper communication between field personnel and the operating authority to allow the operating authority to take the appropriate action until the threat is relieved. Appropriate actions may include a temporary reduction in the line loading or switching the line out of service.

  The protocol for contacting the operating authority should be defined. Some Transmission Owners' processes may require a call directly to the operating authority, while other Transmission Owners may require a call to a supervisor or field forester who will in turn notify the proper operating authority.

> The term "responsible control center" refers to personnel with direct responsibility for operating the transmission lines, such as the Transmission Owner's control center, an Independent System Operator, or other operating entity. In the case where the operating authority is not the Transmission Operator the communication between the Transmission Operator and the operating authority will occur by the normal policies that govern their relationship.

The imminent threat process should be implemented in terms of minutes or hours as opposed to a longer time frame for interim corrective action plans (see R5).

All serious growth or fall-in vegetation-related conditions are not necessarily considered imminent threats under this Standard. For example, some Transmission Owners may have a danger tree identification program that identifies for removal trees with the potential to fall near the line. These trees are not necessarily considered imminent threats under the Standard unless they pose an immediate fall-in threat.

There can be situations involving vegetation that are not considered vegetation-related imminent threats under this Standard. For example, a logging operation on or near the Active Transmission Line ROW can pose an immediate threat of a sustained outage and result in the initiation of an imminent threat process in the same manner as the presence of a nearby crane or the notification of a hot-spot on a conductor connector. Although the logging threat in this example tangentially involves vegetation, it is not considered a vegetation-related imminent threat under the Standard.

Requirement R5:
The intent of this requirement is to deal with situations that prevent the Transmission Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the Transmission Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at immediate risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the Transmission Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the Transmission Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the Transmission Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to immediately mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for each location.

In developing the specific action to mitigate the potential risk to the transmission line the Transmission Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
The Transmission Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:
This requirement sets a minimum time period for the Vegetation Inspections. More frequent inspections may be needed to maintain reliability levels, depending upon such factors as anticipated growth rates of the local vegetation, length of the growing season for the geographical area, limited Active Transmission ROW width, and rainfall amounts. Therefore some lines may be designated with a higher frequency of inspections.

The VSL for Requirement R6 has VSL categories ranked by the percentage of the required ROW inspections completed. To calculate the percentage of inspection completion the Transmission Owner lines may choose units such as: line miles or kilometers, circuit miles or kilometers, pole line miles, ROW miles, etc.

If a Transmission Owner operates 2,000 miles of 230 kV transmission lines this Transmission Owner will be responsible for inspecting all 2,000 miles of 230 kV transmission at least once line during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount inspected would be 1900/2000 = 0.95 or 95%. The "Lower VSL" for R6 would apply in this example.

The standard allows Vegetation Inspections to be performed in conjunction with general line inspections as per the definition.

Requirement R7:
Documentation or other evidence of the work performed typically consists of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, work inspection reports and walk-through reports.

Documentation is required when the annual work plan is adjusted or not completely implemented as originally planned. The reasons for the deferrals or changes and the expected completion date of postponed work should be documented.

The flexibility to adjust the annual work plan must always ensure the reliability of the electric Transmission system. Flexibility is meant to address changing conditions of the vegetation on the Active Transmission Line ROW, emergencies, and other significant changing conditions.

This standard requires that the annual work plan be flexible to allow the Transmission Owner to change priorities during the year as conditions or situations dictate. For example, weather conditions (drought) could make herbicide application ineffective during the plan year. Another situational variance could be a major storm that redirects local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the Transmission Owner’s system to work on another system. Examples of documented adjustments may include deferrals or additions to the annual work plan.

The work plan is not intended to be a “span-by-span” detailed description of all work to be performed. It is intended to require the Transmission Owner to annually plan and schedule vegetation work to prevent encroachment into the MVCD.

The Transmission Owner is required to implement the annual work plan for vegetation management to accomplish the purpose of this standard. This means that vegetation maintenance ought to be performed to the extent of the Transmission Owner’s easement, fee simple and other legal rights. It is intended to address the importance of maintaining all locations on the Active Transmission Line ROWs for reliability purposes in lieu of making special exceptions.

- Property owners and other interested parties occasionally request special considerations to leave undesirable vegetation conditions. Such considerations must never be allowed to impact reliability.
- These undesirable vegetation conditions require more frequent work or inspections than other locations with similar vegetation threats and similar easement rights which are not subject to the special property owner requests.
- The Transmission Owner's vegetation maintenance work necessary to implement the annual work plan is most effective when performed to the maximum extent allowed by any easement, fee simple and other legal rights.
- The Transmission Owner should, therefore, endeavor to maintain its Active Transmission Line ROW to the full extent of its legal rights at all times and in all cases.

A comprehensive approach that exercises the full extent of legal rights is superior to incremental management in the long term because it reduces overall encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient at all locations on the Active Transmission Line ROW .

When developing the annual work plan the Transmission Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Transmission Owners may also need to consider those special landowner requirements as documented in easement instruments.

The following conditions may result in adjustments to the annual work plan: abnormal weather such as drought, major storms, excessive rainfall, other environmental conditions such as infestation, disease, fire, etc. These conditions may be found as part of a special or scheduled

Vegetation Inspection. Examples of annual work plan adjustments that are permitted may include revising the work plan priorities, rescheduling work to another time or selecting alternate vegetation control methods. Changes in land usage made by a property owner, such as timber clearing, may be another condition that warrants an adjustment.

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[3]

For **Alternating Current** Voltages

(AC) Nominal System Voltage (kV)	**(AC) Maximum System Voltage (kV)**	**MVCD feet (meters) sea level**	**MVCD feet (meters) 3,000ft (914.4m)**	**MVCD feet (meters) 4,000ft (1219.2m)**	**MVCD feet (meters) 5,000ft (1524m)**	**MVCD feet (meters) 6,000ft (1828.8m)**	**MVCD feet (meters) 7,000ft (2133.6m)**	**MVCD feet (meters) 8,000ft (2438.4m)**	**MVCD feet (meters) 9,000ft (2743.2m)**	**MVCD feet (meters) 10,000ft (3048m)**	**MVCD feet (meters) 11,000ft (3352.8m)**
765	800	8.06ft (2.46m)	8.89ft (2.71m)	9.17ft (2.80m)	9.45ft (2.88m)	9.73ft (2.97m)	10.01ft (3.05m)	10.29ft (3.14m)	10.57ft (3.22m)	10.85ft (3.31m)	11.13ft (3.39m)
500	550	5.06ft (1.54m)	5.66ft (1.73m)	5.86ft (1.79m)	6.07ft (1.85m)	6.28ft (1.91m)	6.49ft (1.98m)	6.7ft (2.04m)	6.92ft (2.11m)	7.13ft (2.17m)	7.35ft (2.24m)
345	362	3.12ft (0.95m)	3.53ft (1.08m)	3.67ft (1.12m)	3.82ft (1.16m)	3.97ft (1.21m)	4.12ft (1.26m)	4.27ft (1.30m)	4.43ft (1.35m)	4.58ft (1.40m)	4.74ft (1.44m)
230	242	2.97ft (0.91m)	3.36ft (1.02m)	3.49ft (1.06m)	3.63ft (1.11m)	3.78ft (1.15m)	3.92ft (1.19m)	4.07ft (1.24m)	4.22ft (1.29m)	4.37ft (1.33m)	4.53ft (1.38m)
161*	169	2ft (0.61m)	2.28ft (0.69m)	2.38ft (0.73m)	2.48ft (0.76m)	2.58ft (0.79m)	2.69ft (0.82m)	2.8ft (0.85m)	2.91ft (0.89m)	3.03ft (0.92m)	3.14ft (0.96m)
138*	145	1.7ft (0.52m)	1.94ft (0.59m)	2.03ft (0.62m)	2.12ft (0.65m)	2.21ft (0.67m)	2.3ft (0.70m)	2.4ft (0.73m)	2.49ft (0.76m)	2.59ft (0.79m)	2.7ft (0.82m)
115*	121	1.41ft (0.43m)	1.61ft (0.49m)	1.68ft (0.51m)	1.75ft (0.53m)	1.83ft (0.56m)	1.91ft (0.58m)	1.99ft (0.61m)	2.07ft (0.63m)	2.16ft (0.66m)	2.25ft (0.69m)
88*	100	1.15ft (0.35m)	1.32ft (0.40m)	1.38ft (0.42m)	1.44ft (0.44m)	1.5ft (0.46m)	1.57ft (0.48m)	1.64ft (0.50m)	1.71ft (0.52m)	1.78ft (0.54m)	1.86ft (0.57m)
69*	72	0.82ft (0.25m)	0.94ft (0.29m)	0.99ft (0.30m)	1.03ft (0.31m)	1.08ft (0.33m)	1.13ft (0.34m)	1.18ft (0.36m)	1.23ft (0.37m)	1.28ft (0.39m)	1.34ft (0.41m)

[3] The distances in this Table are the minimums required to prevent flashover; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

Table 2 (cont.) — Minimum Vegetation Clearance Distances (MVCD)
For **Direct Current** Voltages

(DC) Nominal Pole to Ground Voltage (kV)	**MVCD feet (meters) sea level**	**MVCD feet (meters) 3,000ft (914.4m) Alt.**	**MVCD feet (meters) 4,000ft (1219.2m) Alt.**	**MVCD feet (meters) 5,000ft (1524m) Alt.**	**MVCD feet (meters) 6,000ft (1828.8m) Alt.**	**MVCD feet (meters) 7,000ft (2133.6m) Alt.**	**MVCD feet (meters) (8,000ft (2438.4m) Alt.**	**MVCD feet (meters) 9,000ft (2743.2m) Alt.**	**MVCD feet (meters) 10,000ft (3048m) Alt.**	**MVCD feet (meters) 11,000ft (3352.8m) Alt.**
±750	13.92ft (4.24m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.9ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.07ft (3.07m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	(13.54ft 4.13m)
±500	7.89ft (2.40m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	4.78ft (1.46m)	5.35ft (1.63m)	5.55ft (1.69m)	5.75ft (1.75m)	5.95ft (1.81m)	6.15ft (1.87m)	6.36ft (1.94m)	6.57ft (2.00m)	6.77ft (2.06m)	6.98ft (2.13m)
±250	3.43ft (1.05m)	4.02ft (1.23m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5ft (1.52m)	5.17ft (1.58m)

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan for FAC-003-2

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

FAC-003-2 — Vegetation Management

Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards.
When FAC-003-2 is approved, a new definition for Active Transmission Line Right-of-Way and a revised definition for Vegetation Inspection should become effective.

The original definition of Vegetation Inspection should be retired when the new definition becomes effective.

FAC-003-1 will be retired when FAC-003-2 becomes effective.

Compliance with Standard

The standard applies to Transmission Owners.

Effective Date

The effective date is the date entities are expected to meet the performance identified in this standard. The effective date allows entities time to make revisions to their existing transmission vegetation management programs to comply with the new requirements.

Requirement	Jurisdiction									
	Alberta	British Columbia	Manitoba	New Brunswick	Newfound-land	Nova Scotia	Ontario	Quebec	Saskatch-ewan	USA
R1	1	1	1	3	TBD	TBD	2	TBD	1	1
R2	1	1	1	3	TBD	TBD	2	TBD	1	1
R3	1	1	1	3	TBD	TBD	2		1	1
R4	1	1	1	3	TBD	TBD	2	TBD	1	1
R5	1	1	1	3	TBD	TBD	2	TBD	1	1
R6	1	1	1	3	TBD	TBD	2	TBD	1	1
R7	1	1	1	3	TBD	TBD	2	TBD	1	1

1. First calendar day of the first calendar quarter one year after applicable regulatory authority approval for all requirements
2. First calendar day of the first calendar quarter one year following Board of Trustees adoption unless governmental authority withholds approval
3. First calendar day of the first calendar quarter that is at least one year following Board of Trustees adoption

Exceptions:

Lines operated below 200kV, designated by the Planning Coordinator as an element of an IROL or as a Major WECC Transfer Path, become subject to this standard 12 months after the date the Planning Coordinator or WECC initially designates the lines as being subject to this standard.

An existing transmission line operated at 200kV or higher that is newly acquired by an asset owner and was not previously subject to this standard, becomes subject to this standard 12 months after the acquisition date of the line(s).

Mapping of FAC-003-2 Draft 2 to FAC-003-2 Draft 3 (Results-based Standard)

Standard FAC-003-2 Draft 2	Comment	Proposed Standard FAC-003-2 RBS (Draft 3)
Standard Development Roadmap	Modified per proposed SCPSC format for RBS	**Standard Development Timeline**
Definitions of Terms Used in Standard	Modified per proposed SCPSC format for RBS	**Definitions of Terms Used in Standard**
Effective Dates	Modified per proposed SCPSC format for RBS. This section now contains a table that lists the various Jurisdictions and their associated Effective Dates.	**Effective Dates**
1. Title: Transmission Vegetation Management	No change	**1. Title:** Transmission Vegetation Management
2. Number: FAC-003-2	No change	**2. Number:** FAC-003-2
3. Purpose: To improve the reliability of the electric Transmission system by preventing those vegetation related outages that could lead to Cascading.	No change	**3. Purpose:** To improve the reliability of the electric transmission system by preventing those vegetation related outages that could lead to Cascading.
4. Applicability: 4.1. Functional Entities: 4.1.1. Transmission Owner 4.1.2. Planning Coordinator 4.2. Facilities: 4.2.1 Transmission lines ("applicable lines") operated at 200kV or higher, and transmission lines operated below 200kV designated by the Planning Coordinator as being subject to this standard	Modified to remove the Planning Coordinator, to include Exceptions in 4.2 and revised Facilities to include only those that meet specified criterion.	**4. Applicability:** **4.1.** Functional Entities: **4.1.1** Transmission Owners **4.2.** Facilities: Defined below, including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities: **4.2.1.** Overhead transmission lines operated at 200kV or higher. **4.2.2.** Overhead transmission lines operated below 200kV having been identified as included in the definition of an IROL. **4.2.3.** Overhead transmission lines operated below 200 kV having been identified as included in the definition of one of the Major WECC Transfer Paths in the Bulk Electric System.

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies"*

Standard FAC-003-2 Draft 2	Comment	Proposed Standard FAC-003-2 RBS (Draft 3)
including but not limited to those that cross lands owned by federal , state, provincial, public, private, or tribal entities. 4.2.2. Transmission lines operated below 200kV designated by the Planning Coordinator as being subject to this standard become subject to this standard 12 months after the date the Planning Coordinator initially designates the transmission line as being subject to this standard. 4.2.3. Existing transmission line(s) operated at 200kV or higher that is newly acquired by a Transmission Owner and was not previously subject to this standard, become subject to this standard 12 months after the acquisition date of the transmission line(s).		**4.2.4.** This Standard does not apply to Facilities identified above (4.2.1 through 4.2.3) located in the fenced area of a switchyard, station or substation. **4.3.** Other: **4.3.1** This Standard does not apply to any occurrence, non-occurrence, or other set of circumstances that are beyond the reasonable control of a Transmission Owner subject to this Reliability Standard, and are not caused by the fault or negligence of the Transmission Owner, including acts of God, flood, drought, earthquake, major storms, fire, hurricane, tornado, landslides, logging activities, animals severing trees, lightning, epidemic, strike, war, riot, civil disturbance, sabotage, vandalism, terrorism, wind shear, or fresh gales that restricts or prevents performance to comply with this reliability standard's requirements.
	Added new section titled, "Background" per SCPSC format.	**5. Background** This NERC Vegetation Management Standard ("Standard") uses a defense-in-depth approach to improve the reliability of the electric Transmission system by preventing those vegetation related outages that could lead to Cascading. This Standard is…
R1. Each Transmission Owner shall have a documented transmission vegetation management program that describes how it conducts work on its Active Transmission Line Rights of Way to avoid Sustained Outages due to vegetation,	Modified R1. by removing prescriptive text in sub parts 1.1 through 1.6. and focused on desired result of requiring competency on the part of	**R3.** Each Transmission Owner shall have a documented transmission vegetation management program that describes how it conducts work on its Active Transmission Line Rights of Way to avoid Sustained Outages due to vegetation, considering all possible locations the conductor may occupy assuming operation within Rating and Rated Electrical Operating Conditions. **R5.** Each Transmission Owner shall take interim corrective action when it is

Mapping of FAC-003-2 Draft 2 to FAC-003-2 Draft 3 (Results-based Standard)

Standard FAC-003-2 Draft 2	Comment	Proposed Standard FAC-003-2 RBS (Draft 3)
considering all possible locations the conductor may occupy under the effects of sag and sway throughout its operating range under rated conditions. The transmission vegetation management program shall: [Violation Risk Factor: Lower][Time Horizon: Long-term planning] 1.1. Specify the methodologies that the Transmission Owner uses to control vegetation. 1.2. Specify a Vegetation Inspection frequency of at least once per calendar year that takes into account local and environmental factors. 1.3. Require an annual work plan that identifies the applicable lines to be maintained and associated work to be performed during the year. It shall be flexible to adjust to changing conditions and to findings from Vegetation Inspections. Adjustments to the plan within the year are permissible. The plan shall take into consideration permitting and scheduling requirements from landowners or regulatory authorities. It shall support the objectives of the transmission vegetation management program and utilize the methodologies outlined in the transmission vegetation management program. 1.4. Require a process or procedure for response to imminent threats of a vegetation-related Sustained Outage. The process or procedure shall specify actions which shall include immediate communication of the threat to the Transmission Operator or proper operating authority. The process or	Transmission Owner. Elevated interim corrective actions to a standalone requirement to focus on desired result of working around impediments. Moved VRF and Time Horizon.	temporarily constrained from performing planned vegetation work, where a transmission line is put at potential risk due to the constraint.

Standard FAC-003-2 Draft 2	Comment	Proposed Standard FAC-003-2 RBS (Draft 3)
procedure shall specify what conditions warrant a response. 1.5. Specify an interim corrective action process for use when the Transmission Owner is constrained from performing vegetation maintenance as planned. 1.6. Specify the maintenance approach used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that Table 1 clearances are never violated. The maintenance approach shall consider the sag and sway of the conductor throughout its operating range under rated conditions.		
R2. Each Transmission Owner shall implement its imminent threat process or procedure when the Transmission Owner has actual knowledge of such a threat, obtained through normal operating practices.	Revised to focus on desired result to notify of imminent threats. Moved VRF and Time Horizon.	**R4.** Each Transmission Owner shall notify the responsible control center when it has verified knowledge of a vegetation imminent threat condition. A vegetation imminent threat condition is one which is likely to cause a Sustained Outage at any moment.
R3. Each Transmission Owner shall conduct Vegetation Inspections of all applicable lines (as measured in line miles) in accordance with the frequency specified in its transmission vegetation management program, unless constrained by natural disasters. When constrained by a natural disaster, the Transmission Owner shall conduct the Vegetation Inspection(s) within six months or a period agreed to by its Regional Entity, whichever is greater.	Revised to focus on desired result of inspecting for vegetation annually and to eliminate prescriptive text. Moved VRF and Time Horizon.	**R6.** Each Transmission Owner shall perform a Vegetation Inspection of all applicable lines once per calendar year, at a minimum.

Mapping of FAC-003-2 Draft 2 to FAC-003-2 Draft 3 (Results-based Standard)

Standard FAC-003-2 Draft 2	Comment	Proposed Standard FAC-003-2 RBS (Draft 3)
R4. Each Transmission Owner shall prevent encroachment of vegetation into the Minimum Vegetation Clearance Distances (MVCD) listed in FAC-003-2 - Attachment 1 for its applicable lines as observed in real-time operating between no-load and their Rating, with the following exceptions: *[Violation Risk Factor — Medium][Time Horizon — Real Time]* Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from natural disasters.[2] Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from human or animal activity.[3] Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from falling vegetation. **R5.** Each Transmission Owner shall prevent Sustained Outages[4] of applicable lines that are identified as an element of an Interconnection Reliability Operating Limit (IROL) (or Major WECC Transfer Path) due to vegetation growing into a conductor operating between no-load and its Rating, with the following exceptions: *[Violation Risk Factor — High][Time Horizon — Real Time]* • Sustained Outages of applicable	Revised to focus on desired result of keeping vegetation out of a minimum clearance distance from transmission lines and to improve clarity. Combined R4, R4, R6, R7, and R8 into two standalone requirements. Moved VRFs and Time Horizons.	**R1.** Each Transmission Owner shall prevent vegetation from encroaching within the Minimum Vegetation Clearance Distance (MVCD) of line conductors that are identified as an element of an IROL or Major WECC Transfer Path (operating within Rating and Rated Electrical Operating Conditions) to avoid a Sustained Outage. **R2.** Each Transmission Owner shall prevent vegetation from encroaching within the Minimum Vegetation Clearance Distance (MVCD) of applicable line conductors, which are not elements of an IROL and are not a Major WECC Transfer Path, (operating within Rating and Rated Electrical Operating Conditions) to avoid a Sustained Outage.

[2] Examples include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods.

[3] Examples include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation.

[4] Multiple Sustained Outages on an individual line, if caused by the same vegetation, shall be considered as one outage regardless of the actual number of outages within a 24-hour period.

Standard FAC-003-2 Draft 2	Comment	Proposed Standard FAC-003-2 RBS (Draft 3)
lines that result from natural disasters. • Sustained Outages of applicable lines that result from human or animal activity. **R6.** Each Transmission Owner shall prevent Sustained Outages of applicable lines that are not an element of an IROL (or major WECC Transfer Path) due to vegetation growing into a conductor operating between no-load and its Rating, with the following exceptions: *[Violation Risk Factor — Medium][Time Horizon — Real Time]* • Sustained Outages of applicable lines that result from natural disasters. • Sustained Outages of applicable lines that result from human or animal activity. **R7.** Each Transmission Owner shall prevent Sustained Outages of applicable lines due to the blowing together of vegetation and a conductor within an Active Transmission Line Right of Way (operating within design blow-out conditions) with the following exception: *[Violation Risk Factor — Medium][Time Horizon — Real Time]* Sustained Outages of applicable lines that result from natural disasters or wind-blown debris. **R8.** Each Transmission Owner shall prevent Sustained Outages of applicable lines due to vegetation falling into a conductor from within an Active Transmission Line Right of Way with the following exceptions: *[Violation Risk Factor —*		

Standard FAC-003-2 Draft 2	Comment	Proposed Standard FAC-003-2 RBS (Draft 3)
Medium] [Time Horizon — Real Time] • Sustained Outages of applicable lines that result from natural disasters or wind-blown debris. • Sustained Outages of applicable lines that result from human or animal activity.		
R9. Each Transmission Owner shall implement its annual work plan for vegetation management to accomplish the purpose of this standard.	Moved VRF and Time Horizon.	**R7.** Each Transmission Owner shall execute a flexible annual vegetation work plan to ensure no encroachments within the MVCD.
R10. Each Planning Coordinator shall prepare and review annually, a list of lines that are operated below 200kV, if any, which are subject to this standard. Each Planning Coordinator shall consult with its Transmission Owner(s) and neighboring Planning Coordinators to obtain input to develop the list.	Revised to add applicability sections 4.3.2 and 4.3.3 and eliminated this requirement.	**4.3.2.** Overhead transmission lines operated below 200kV having been identified as elements of an IROL. **4.3.3.** Overhead transmission lines operated below 200 kV having been included in the definition of one of the Major WECC Transfer Paths in the Bulk Electric System.
R11. Each Planning Coordinator shall develop and document its method for assessing the reliability significance of sub-200kV transmission lines whose loss would place the grid at an unacceptable risk of instability, separation, or cascading failures.	Revised to add applicability sections 4.3.2 and 4.3.3 and eliminated this requirement.	**4.3.2.** Overhead transmission lines operated below 200kV having been identified as elements of an IROL. **4.3.3.** Overhead transmission lines operated below 200 kV having been included in the definition of one of the Major WECC Transfer Paths in the Bulk Electric System.

Unofficial Comment Form for 3rd Draft of FAC-003-2 Transmission Vegetation Management — Part of Project 2007-07 Vegetation Management

Please **DO NOT** use this form to submit comments. Please use the electronic form located at the site below to submit comments on the 3rd Draft of FAC-003-2 Transmission Vegetation Management. Comments must be submitted by **March 31, 2010**

http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

If you have questions please contact Harry Tom at Harry.Tom@nerc.net or by telephone at (860) 550-4157.

Background Information

The purpose of Project 2007-07 Vegetation Management is to:

- Assist in providing an adequate level of reliability for the North American electric Transmission System by verifying that the FAC-003-2 Transmission Vegetation Management standard is complete and that its requirements are set at an appropriate level to ensure reliability.
- Incorporate other general improvements described in the Standard Review Guidelines to bring FAC-003-2 Transmission Vegetation Management into conformance with the latest version of the Reliability Standards Development Procedure and the ERO Sanctions Guidelines.
- Consider comments received from ERO regulatory authorities and stakeholders on FAC-003-1 Transmission Vegetation Management as noted in the NERC Standards Issues Database.
- Satisfy the requirement for review of FAC-003-2 Transmission Vegetation Management within five-year review cycle.

In addition, on January 14, 2010, the NERC Standards Committee endorsed the use of Project 2007-07 Vegetation Management as the prototype for the proof-of-concept for using the results-based criteria for developing a reliability standard. The results-based initiative is intended to focus the collective effort of NERC and industry participants on improving the clarity and quality of NERC reliability standards by developing performance-based, risk-based and competency-based requirements that accomplish a reliability objective through a defense-in-depth strategy, while eliminating documentation-driven requirements that do not have an impact on bulk power system reliability.

The Standards Committee also directed the standard drafting team for Project 2007-07 Vegetation Management to do so with a target for final industry ballot of draft FAC-003-2 Transmission Vegetation Management by August 31, 2010.

The criteria for developing a results-based reliability standard include:

1. Strive to achieve a portfolio of performance-based, risk-based, and competency-based mandatory reliability requirements that provide an effective defense-in-depth strategy for achieving an adequate level of reliability of the bulk power system.
    a) **Performance-based** — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four

components: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome*?

b) **Risk-based** — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome* *that reduces a stated risk to the reliability of the bulk power system?*

c) **Competency-based** — defines a minimum capability an entity needs to have to demonstrate it is able to perform its designated reliability functions.

2. The defense-in-depth strategy for reliability standards development should recognize that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.
3. Each requirement should identify a clear and measurable expected outcome, such as: i) a stated level of reliability performance, ii) a reduction in a specified reliability risk, or iii) a necessary competency.
4. Strive to minimize prescriptive, administrative (document something), and commercial requirements within the set of NERC reliability standards (i.e., these types of requirements are permissible in standards but should be the exception rather then the rule).
5. A requirement should not prescribe commercial business practices which do not contribute directly to reliability.

The Vegetation Management Standard Drafting Team worked with Ivy Hooks of Compliance Automation, Inc. to apply the “results-based” approach to developing requirements that are clear and enforceable. Ivy is the CEO of Compliance Automation and has shared a wealth of knowledge and expertise with the drafting team. The “look and feel” of the proposed standard contains much more information than we have been including in previous standards, thus the look and feel of the draft FAC-003-2 Transmission Vegetation Management standard is quite different from the look of our existing standards. One of the more obvious changes is the addition of information to aid end users in reading the requirements from a common understanding of the standard’s objective and the rationale for including each requirement. During the Three-year Performance Assessment, stakeholders indicated that they wanted more information to assist in applying standards – and the additional details provided in the proposed Vegetation Management standard provide an example of one way to fill that void.

On February 11, 2010 the Standards Committee authorized the standard drafting team for Project 2007-07 Vegetation Management to take the following actions relative to the development of draft FAC-003-2 Transmission Vegetation Management:

- Discontinue work in developing a complete Consideration of Comments Report for the comments received in response to the posting of the second draft of the draft FAC-003-2 Transmission Vegetation Management standard that was posted in August 2009; however, post the comments received along with a summary of the actions taken by the team in response to those comments but without an individual response to each comment provided.

- Use informal comment periods to collect comments on future "drafts" of the standard, post the comments received during the informal comment periods along with a summary of how the team used the comments received and a redline version of the standard showing the changes made based on the comments received.
- Conduct a 45-day formal comment period in parallel with the formation of the ballot pool and the initial ballot of the standard; post the comments from the formal comment period as they are received for at least the first 30 days of the comment period.
- Use a standard template that is different from the template stipulated in the Reliability Standard Development Procedure as provided by the Standards Committee's Process Subcommittee.

With respect to the first bullet above regarding stakeholder comments submitted in response to the posting of the second draft of the proposed standard, the SDT has posted a general summary response to the comments on the draft which was posted in August, 2009. However, the limited response does not mean that the SDT ignored the comments received in August 2009. The SDT carefully considered those comments and made modifications to the standard based on the comments received. A summary of the SDT considerations has been posted on the NERC website in lieu of a full Consideration of Comments Report.

A subset of comments received during the August 2009 posting suggested that the STD for this project (Project 2007-07 Vegetation Management) address the recommendations in the Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface that pertain to FAC-003-1 Transmission Vegetation Management. The SDT for this project respectfully declined to address the referenced recommendations primarily for the following reasons:

- Project 2010-07 Transmission Requirements at the Generator Interface has been established to address the recommendations in the Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface.
- The referenced recommendations are outside the scope of the Standard Authorization Request for this project (Project 2007-07 Vegetation Management).
- The appointed SDT does not have the proper representation to address the referenced recommendations.

Significant modifications incorporated into this draft of FAC-003-2 Transmission Vegetation Management include:

- Two new sections have been added: Background and Guideline and Technical Basis. While the titles are self-evident, the SDT would like to point out that this information was previously included for review in the Technical Reference (aka, White Paper).
- A "global" Force Majeure statement was added to the Applicability section of the standard in response to comments received. This statement is included at the front of the standard and thus is applicable to all Requirements. This "exclusion language" was included in a footnote in the prior version of the standard.
- The wording relating to expected conductor positions was modified. The previous draft of the standard referred to "operating within Rating under normal conditions" and/or "sag and sway". With this draft, and in response to comments received on this issue, the wording was changed, to state "operating within Rating under Rated Electrical Operating Conditions". This modification uses standard NERC glossary

terms to indicate the expectation that vegetation management should account for line operation as designed but not, for example, for overloaded conditions or excessive wind speeds.

With respect to the format of the draft FAC-003-2 Transmission Vegetation Management standard currently posted for informal comment, the NERC Standards Committee's Process Subcommittee (SCPS) has developed a proposed standard template for use by the standard drafting team for Project 2007-07 Vegetation Management. The proposed template is intended to meet the following key objectives:

1. Depicting the basic criteria for writing standard requirements that meet the Results-Based Reliability Standards concepts;
2. Having one Section that contains only the reliability requirements and associated measures;
3. Moving the administrative and compliance information that is not required for reliability into different sections so that there are "homes" for these materials;

In addition, the new template contains the following features/changes:

1. Allowing insertion of explanatory text to help readers better understand the basis of the definitions and requirements;
2. Moving the standard development timeline (previously called roadmap), revision history and effective date(s) up front before the Introduction Section;
3. Grouping Requirements and their corresponding Measures together;
4. Grouping VRFs, Time Horizons and VSLs - all of which are used only in the determination of a penalty or sanction - together in a table while leaving the requirements and measures free of any of the compliance elements.

The following questions will assist the SDT in finalizing the development of FAC-003-2 Transmission Vegetation Management and will also assist the Standards Committee's Process Subcommittee in refining the proposed standard template. For questions where you agree with indicated statement, please state that you agree and if able, please provide supporting documentation. If you disagree with the statement, please explain why you disagree and provide a rationale to support your position. We would appreciate responses to as many of the following questions as possible.

1. In response to comments received regarding potential for "double jeopardy" and to provide differentiation between transmission lines designated as having IROLs and Major WECC transfer paths from those that are not, the SDT consolidated requirements R4 though R8 found in the August 2009 draft of FAC-003-2 into two requirements in the latest draft of FAC-003-2 (new requirements R1 and R2). Do you agree? Please explain.

   ☐ Yes

   ☐ No

   Comments:

2. The results-based reliability standard criteria focus on striving to achieve a portfolio of performance-based, risk-based, and competency-based mandatory reliability requirements that provide an effective defense-in-depth strategy for achieving an

adequate level of reliability of the bulk power system in lieu of prescriptive requirements. Consequently, the SDT revised R1 and its subparts found in the August 2009 draft of FAC-003-2 in favor of the text in the latest draft of FAC-003-2 (new requirement R3). Do you agree? Please explain.

☐ Yes

☐ No

Comments:

3. Do you agree with the overall layout of the proposed template? If not, please suggest an alternative layout.

☐ Yes

☐ No

Comments:

4. Do you agree with grouping the standard development timeline (previously called roadmap) with the revision history, and the effective date(s) and putting this administrative information up front before the Introduction Section? Please explain.

☐ Yes

☐ No

Comments:

5. Do you agree with grouping the Requirements and Measures together, in one Section now called Requirements and Measures? Please explain.

☐ Yes

☐ No

Comments:

6. Do you agree with grouping VRFs, Time Horizons and VSLs together, and putting them in a table separate from the Requirements and Measures Section? Please explain.

☐ Yes

☐ No

Comments:

7. Do you agree with the insertion of text boxes, where necessary, to help readers better understand the basis of the Definitions and Requirements? Please explain.

☐ Yes

☐ No

Comments:

8. Do you agree with the addition of a Guideline and Technical Basis Section to place technical materials and other related information that assists entities in understanding

how to comply with the standard but does not contain mandatory actions/activities? Please explain.

☐ Yes

☐ No

Comments:

9. Do you prefer putting URL links to reference materials in the Guideline and Technical Basis Section, or do you prefer putting the additional technical/information materials in appendices, where needed, to supplement the Guideline and Technical Basis Sections? Please explain.

☐ Prefer the inclusion of URL links

☐ Prefer appendices

Comments:

10. Do you agree with the addition of the Background Section to allow provision of background information, and to elaborate on the reliability-related drivers for the standard/change? Please explain.

☐ Yes

☐ No

Comments:

11. Do you agree with the addition of an Administrative Procedure Section to place administrative/procedural requirements that are contained in the existing standards but which do not meet the results-based or risk-based criteria? Please explain.

☐ Yes

☐ No

Comments:

12. Is there any other information that should be included in the standard document? If so, please explain why you feel that this information should be included.

☐ Yes

☐ No

Comments:

13. Do you have any other comment regarding the draft FAC-003-2 Transmission Vegetation Management standard that have not been addressed above? If yes, please provide a reference to the section, requirement, or subrequirement that you believe should be changed, added or deleted and the rationale for your proposal.

☐ Yes

☐ No

Comments:

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Transmission Vegetation Management

Standard FAC-003-2 Technical Reference

Vegetation Management Standard Drafting Team

to ensure the reliability of the bulk power system

March 17, 2010

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Table of Contents

Introduction

This document is intended to provide supplemental information and guidance for complying with the requirements of Reliability Standard FAC-003-2.

The purpose of the Standard is to improve the reliability of the electric transmission system by preventing those vegetation related outages that could lead to Cascading.

Compliance with the Standard is mandatory and enforceable.

Special Note: The Application of Results-Based Approach to FAC-003-2

In its three-year assessment as the ERO, NERC acknowledged stakeholder comments and committed to:

i) addressing quality issues to ensure each reliability standard has a clear statement of purpose, and has outcome-focused requirements that are clear and measurable; and

ii) eliminating requirements that do not have an impact on bulk power system reliability.

In 2010, the Standards Committee approved a recommendation to use Project 2007-07 Vegetation Management as a first proof of concept for developing results-based standards.

The Standard Drafting Team (SDT) employed a defense-in-depth[1] strategy for FAC-003-2, where each requirement has a role in preventing those vegetation related outages that could lead to Cascading. This portfolio of requirements was designed to achieve an overall defense-in-depth strategy and to comply with the quality objectives identified in the *Acceptance Criteria of a Reliability Standard* document.

The SDT developed a portfolio of performance, risk, and competency-based mandatory reliability requirements to support an effective defense-in-depth strategy. Each Requirement was developed using one of the following requirement types:

a. Performance-based - defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. Risk-based - preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. Competency-based - defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

[1] A defense-in-depth strategy for reliability standards recognizes that each requirement in the NERC standards has a role in preventing system failures, and that these roles are complementary and reinforcing. These prevention measures should be arranged in a series of defensive layers or walls. No single defensive layer provides complete protection from failure by itself. But taken together, with well-designed layers including performance, risk, and competency-based, requirements, a defense-in-depth approach can be very effective in preventing future large scale power system failures.

The drafting team reviewed and edited version 1 of FAC-003-1 to remove prescriptive and administrative language in order to distill the technical requirements down to their essential reliability content. Text that is explanatory in nature is placed in a special section of the standard entitled Guideline and Technical Basis to aid in the understanding of the requirements. Furthermore, Rationale text boxes are inserted alongside each requirement to communicate the foundation for the requirement.

Disclaimer

This supporting document is supplemental to the reliability standard FAC-003-2 — Transmission Vegetation Management and does not contain mandatory requirements subject to compliance review.

Definition of Terms

Active Transmission Line Right of Way* — A strip or corridor of land that is occupied by active transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities.

Examples of active portions of corridors include:

1) The width of any Active Transmission Line Right-of-Way (ROW) is the portion of the ROW that has been cleared of vegetation to meet design clearance requirements such as National Electrical Safety Code or other design criteria, for the reliable operation of active facilities.

Examples of inactive portions of corridors include:

2) The portions of the right of way acquired to accommodate future facilities. Power plant exits are examples where large rights-of-way are obtained for maximum corridor utilization and may currently have fewer structures constructed.
3) The portion of the ROW where corridor edge zones are designated by regulatory bodies for vegetation to exist.
4) The portions of the ROW where double-circuit structures are installed but only one circuit is currently strung with conductors.

Vegetation Inspection** — The systematic examination of vegetation conditions on an Active Transmission Line Right-of-Way which may be combined with a general line inspection.

The inspection includes the identification of any vegetation that may pose a threat to reliability prior to the next planned inspection or maintenance work, considering the current location of the conductor and other possible locations of the conductor due to sag and sway for rated conditions.

This definition allows both maintenance inspections and vegetation inspections to be performed concurrently.

*To be added to the NERC glossary of terms with final approval of this standard revision
** This is a modification to a defined term in the NERC glossary.

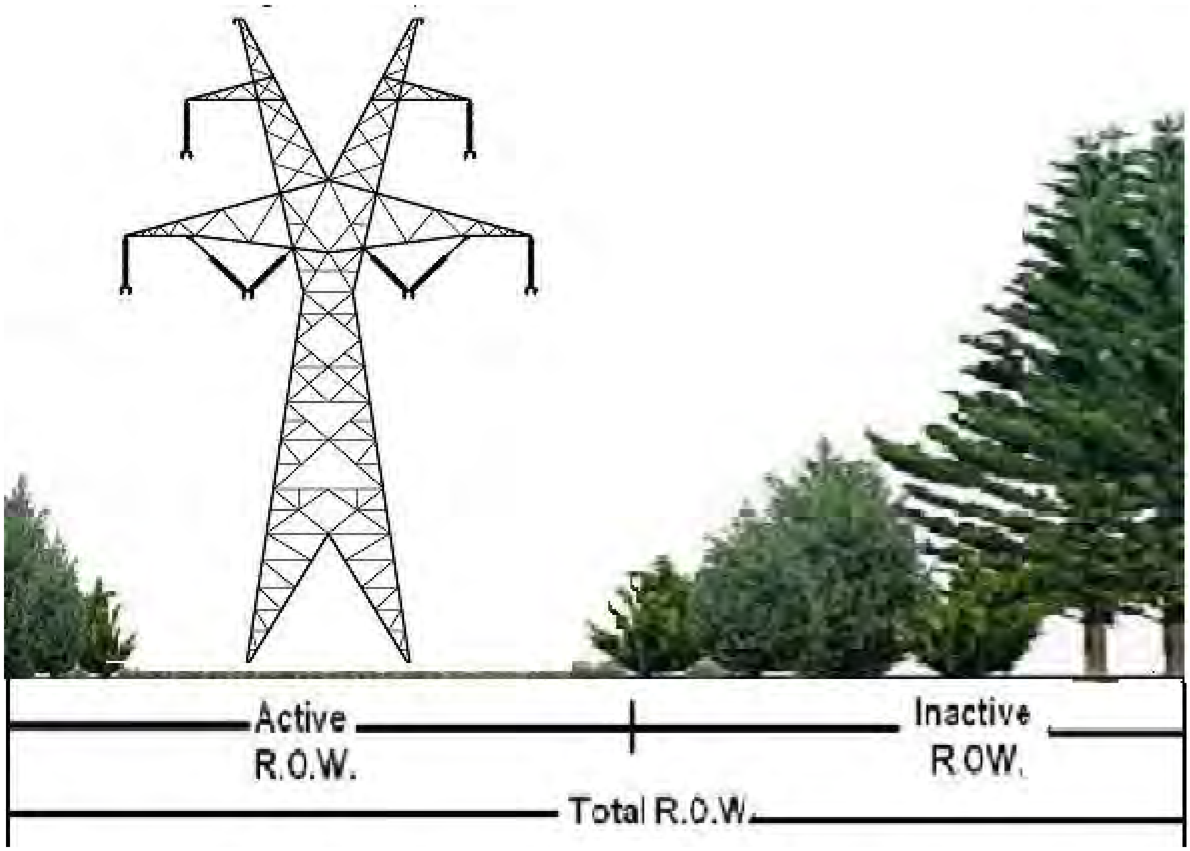

Figure 1

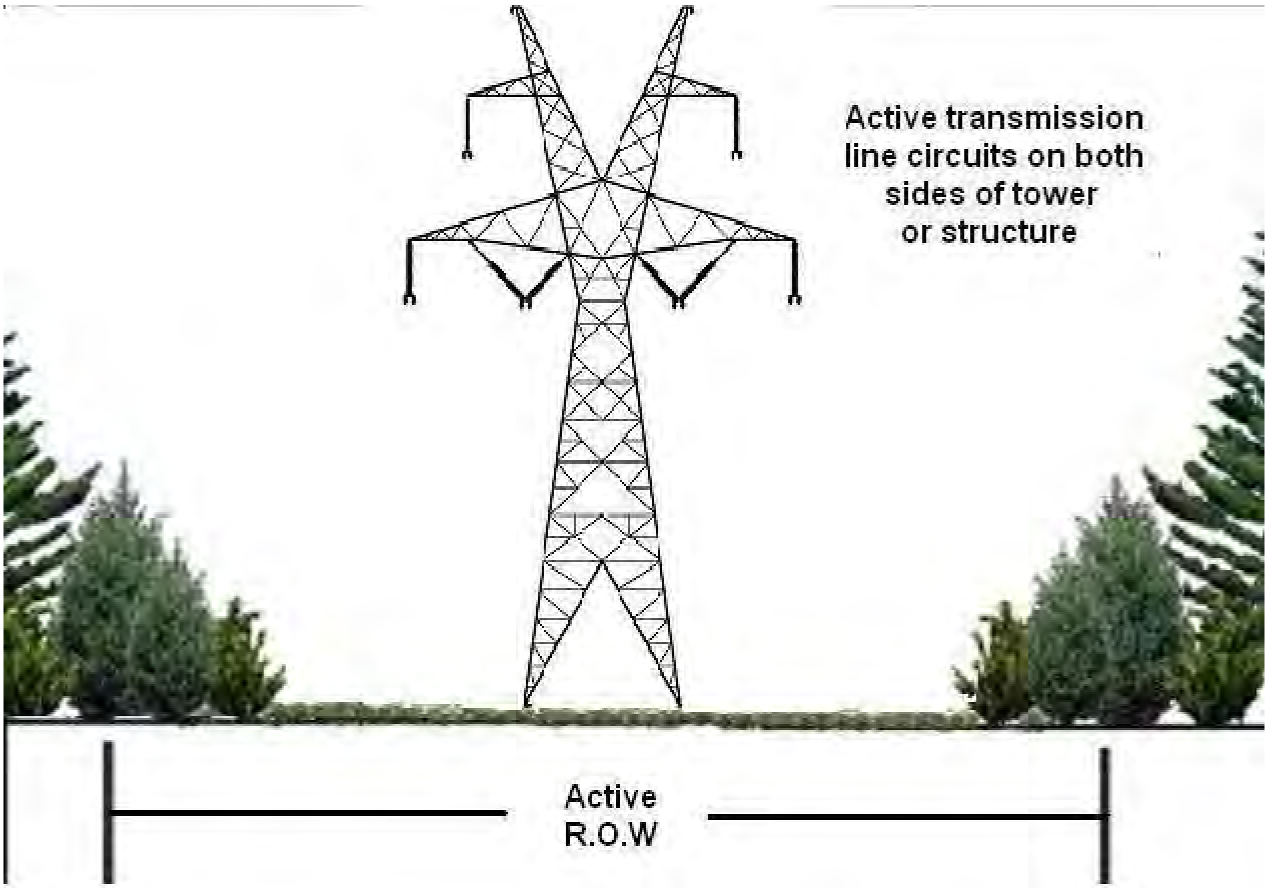
Active transmission
line circuits on both
sides of tower
or structure
Active
R.O.W

Figure 2

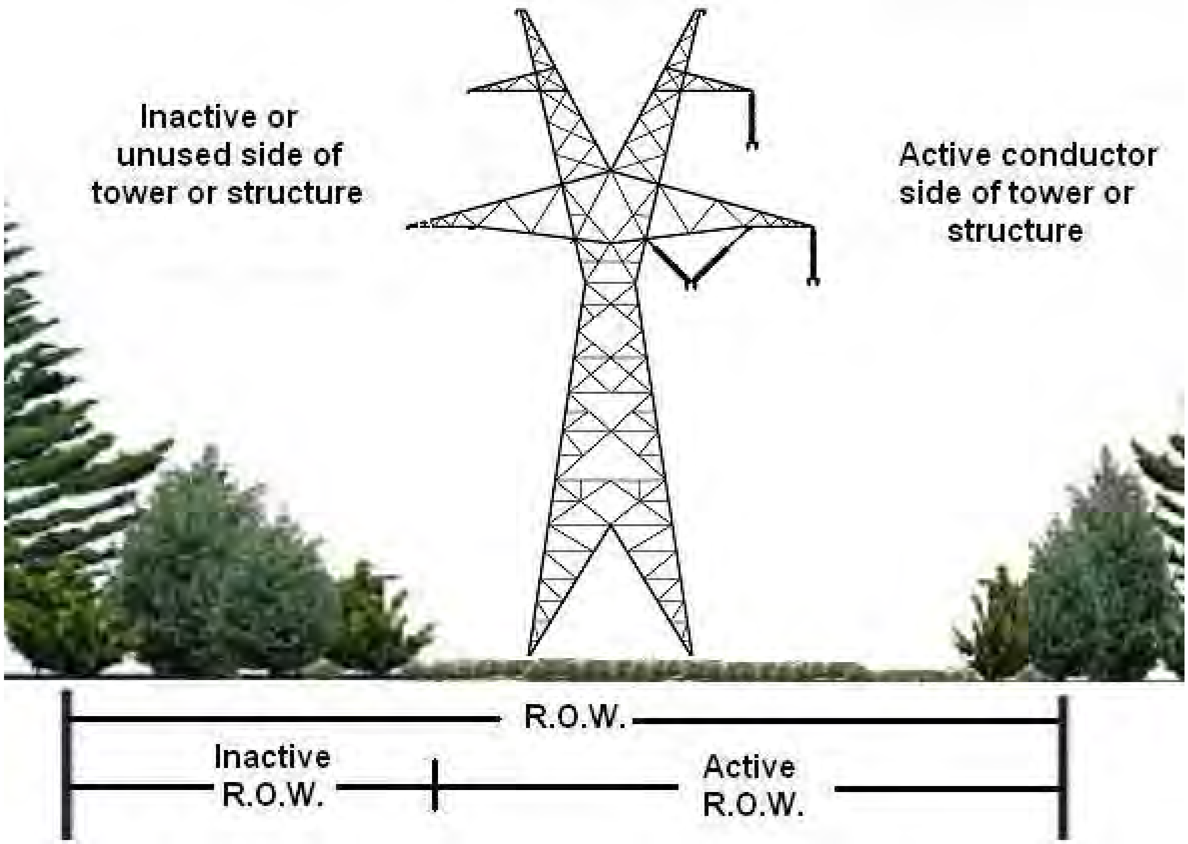
Inactive or
unused side of
tower or structure
Active conductor
side of tower or
structure
R.O.W.
Inactive
R.O.W.
Active
R.O.W.

Figure 3

Applicability of the Standard

4. Applicability

4.1. Functional Entities:

4.1.1 Transmission Owners

4.2. Facilities: Defined below, including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities:

4.2.1 Overhead transmission lines operated at 200kV or higher.

4.2.2 Overhead transmission lines operated below 200kV having been identified as elements of an Interconnection Reliability Operating Limit (IROL).

4.2.3 Overhead transmission lines operated below 200 kV having been identified as included in the definition of one of the Major WECC Transfer Paths in the Bulk Electric System.

4.2.4 This Standard does not apply to Facilities identified above (4.2.1 through 4.2.3) located in the fenced area of a switchyard, station or substation.

4.3. Other:

4.3.1 This Standard does not apply to any occurrence, non-occurrence, or other set of circumstances that are beyond the reasonable control of a Transmission Owner subject to this Reliability Standard, and are not caused by the fault or negligence of the Transmission Owner, including acts of God, flood, drought, earthquake, major storms, fire, hurricane, tornado, landslides, logging activities, animals severing trees, lightning, epidemic, strike, war, riot, civil disturbance, sabotage, vandalism, terrorism, wind shear, or fresh gales that restricts or prevents performance to comply with this reliability standard's requirements.

In Order 693, FERC discussed the 200 kV bright-line test of applicability. While FERC did not change the 200 kV bright line, the Commission remained concerned that there may be some transmission lines operating at lesser voltages that could have significant impact on the Bulk Electric System that should therefore be subject to this standard.

NERC Standard FAC-014 has the stated purpose, "*To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.*" FAC-014 requires Reliability Coordinators, Planning Coordinators, and Transmission Planners to have a methodology to identify all lines that might comprise an IROL. Thus, these entities would identify sub-200 kV lines that qualify as part of an IROL and should be subject to FAC-003-2.

Although all three entities may prepare the list of elements, FAC-003-2 presently does not specify that it is the list from the Planning Coordinator that should be used by Transmission Owners for FAC-003. However, the Time Horizon needed to plan vegetation management work does not lend itself to the operating horizon of a Reliability Coordinator. Additionally, the Planning Coordinator has a wider-area view than the Transmission Planner and could thus identify any elements of importance to a sub-set of its area that might be missed by a Transmission Planner.

Transmission Owners, who do not already get the list of circuits included in the definition of an IROL, can get them from the Planning Coordinator. Specifically R5 of FAC-014 specifies that "*The Reliability Coordinator, Planning Authority (Coordinator) and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits"*

Vegetation-related Sustained Outages that occur due to natural disasters are beyond the control of the Transmission Owner. These events are not classified as vegetation-related Sustained Outages and are therefore exempt from the Standard. Transmission lines are not designed to withstand the impacts of natural disasters such as tornadoes, hurricanes, severe ice loads, landslides, etc. In the aftermath of catastrophic system damage from natural disasters the Transmission Owner's focus is on electric system restoration for public safety and critical support infrastructure.

Sustained Outages due to human or animal activity are beyond the control of the Transmission Owner. These outages are not classified as vegetation-related Sustained Outages and are therefore exempt from the Standard. Examples of these events may include new plantings by outside parties of tall vegetation under the transmission line planted since the last Vegetation Inspection, tree contacts with line initiated by vehicles, logging activities, etc.

The foregoing exemptions are addressed in a new subsection, <u>4.3 Other,</u> of the Applicability section. Referred to collectively as force majeure events and activities, this section applies to all requirements in FAC-003-2.

The reliability objective of this NERC Vegetation Management Standard ("Standard") is to prevent vegetation-related outages which could lead to Cascading by effective vegetation maintenance while recognizing that certain outages such as those due to vandalism, human errors and acts of nature are not preventable. Operating experience clearly indicates that trees that have grown out of specification could contribute to a cascading grid failure, especially under heavy electrical loading conditions.

Serious outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. To properly reduce and manage this risk, it is necessary to apply the Standard to applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee. For the purposes of the Standard and this technical paper, the term "public lands" includes municipal lands, village lands, city lands, and land owned by a host of other governmental entities.

The Standard addresses vegetation management along applicable overhead lines that serve to connect one electric station to another. However, it is not intended to be applied to lines sections inside the electric station fence or other boundary of an electric station or underground lines.

The Standard is intended to reduce the risk of Cascading involving vegetation. It is not intended to prevent customer outages from occurring due to tree contact with all transmission lines and voltages. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this Standard is not written to address such isolated situations which have little impact on the overall Bulk Electric System. In fact, the inclusion of such a transmission line (which does not lead to the undesirable conditions listed in Requirement R10) on the Planning Coordinator's list of sub-200kV lines may constitute a violation of Requirement R10.

Vegetation growth is constant and always present. Unmanaged vegetation poses an increased outage risk when numerous transmission lines are operating at or near their Rating. This poses a significant risk of multiple line failures and Cascading. On the other hand, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are statistically intermittent. The probability of occurrence of these events is not dependent on heavy loads. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures.

In preparing the original vegetation management standard in 2005, industry stakeholders set the threshold for applicability of the standard at 200kV. This was because an unexpected loss of lines operating at above 200kV has a higher probability of initiating a widespread blackout or cascading outages compared with lines operating at less than 200kV.

The NERC vegetation management standard FAC-003-1 also allowed for application of the standard to "critical" circuits (critical from the perspective of initiating widespread blackouts or cascading outages) operating below 200kV. While the percentage of these circuits is relatively low, it remains a fact that there are sub-200kV circuits whose loss could contribute to a widespread outage. Given the very limited exposure and unlikelihood of a major event related to these lower-voltage lines, it would be an imprudent use of resources to apply the Standard to all sub-200kV lines. The drafting team, after evaluating several alternatives, selected the IROL and WECC Major Transfer Path criteria to determine applicable lines below 200 kV that are subject to this standard.

Requirements R1 and R2

> **Rationale**
> The MVCD is a calculated minimum distance stated in feet (meters) to prevent spark-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method.

R1. *Each Transmission Owner shall prevent vegetation from encroaching within the Minimum Vegetation Clearance Distance (MVCD) of each line conductor that is identified as an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions) to avoid a Sustained Outage.*

R2. *Each Transmission Owner shall prevent vegetation from encroaching within the MVCD of each applicable line conductor, which are not elements of an IROL and are not a Major WECC transfer path, (operating within Rating and Rated Electrical Operating Conditions) to avoid a Sustained Outage.*

M1. *Evidence of violation of Requirement R1 is limited to:*

- *Real-time observation of encroachment into the MVCD, or*
- *A vegetation-related Sustained Outage due to a fall-in from inside the Active Transmission Line ROW, or*
- *A vegetation-related Sustained Outage due to blowing together of applicable lines and vegetation located inside the Active Transmission Line ROW, or*
- *A vegetation-related Sustained Outage due to a grow-in.*

Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

M2. *Evidence of violation of Requirement R2 is limited to:*

- *Real-time observation of encroachment into the MVCD, or*
- *A vegetation-related Sustained Outage due to a fall-in from inside the Active Transmission Line ROW, or*
- *A vegetation-related Sustained Outage due to blowing together of applicable lines and vegetation located inside the Active Transmission Line ROW, or*
- *A vegetation-related Sustained Outage due to a grow-in.*

Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the prevention of vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements, however, they apply to different Facilities. Both R1 and R2 require each Transmission Owner to prevent vegetation from encroaching within the Minimum Vegetation Clearance Distance of transmission lines. R1 is applicable to lines “identified as an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions) to avoid a Sustained Outage”. R2 applies to all other applicable lines that are not an element of an IROL or Major WECC Transfer Path.

The separation of applicability (between R1 and R2) recognizes that an encroachment into the MVCD of an IROL or Major WECC Transfer Path transmission line is a greater risk to the electric transmission system. Applicable lines that are not an element of an IROL or Major WECC Transfer Path are required to be clear of vegetation but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

These requirements (R1 and R2) state that if vegetation encroaches within the distances prescribed in Table 1 in Appendix 1 of this Technical Reference document, it is in violation of the standard. Table 1 delineates the distances necessary to prevent spark-over based on the Gallet equations as described more fully in Appendix 1.

This requirement assumes that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its rating (potentially in violation of other standards), the occurrence of a clearance encroachment may not be a violation of this Standard. Conductor position, and the associated vegetation distance, that result from operation of a transmission line beyond its recognized Rating (for example emergency actions taken by a TOP or RC to protect an Interconnection) is beyond the scope of this standard.

Evidence of violation of Requirement R1 and R2 is limited to a real-time observation of encroachment into the MVCD, or a vegetation-related Sustained Outage due to a fall-in from inside the Active Transmission Line ROW, or a vegetation-related Sustained Outage due to blowing together of applicable lines and vegetation located inside the Active Transmission Line ROW, or a vegetation-related Sustained Outage due to a grow-in.

It is also important to note that Multiple Sustained Outages on an individual line can be caused by the same vegetation. Such events are considered to be a single vegetation-related Sustained Outage under the Standard where the Sustained Outages occur within a 24 hour period.

Requirement R3

R3. *Each Transmission Owner shall have a documented transmission vegetation management program that describes how it conducts work on its Active Transmission Line ROWs to avoid Sustained Outages due to vegetation, considering all possible locations the conductor may occupy assuming operation within Rating and Rated Electrical Operating Conditions.*

Rationale
Provide a basis for evaluation on the intent and competency of the Transmission Owner in maintaining vegetation. There may be many acceptable approaches to maintain clearances. However, the Transmission Owner should be able to state what its approach is and how it conducts work to maintain clearances. See Figure 1 for an illustration of possible conductor locations.

M3. *Each Transmission Owner has a documented transmission vegetation management program that describes how it conducts work on its Active Transmission Line ROW to avoid Sustained Outages due to vegetation, considering all possible locations the conductor may occupy assuming operation within Rating and Rated Electrical Operating Conditions.*

Whitepaper for section R3: (Competency Based Requirement)

Requirement R3 is a competency based requirement concerned with the content of the TVMP and supporting documentation.

An adequate transmission vegetation management program formally establishes the approach the Transmission Owner uses to plan and perform vegetation work that is necessary to prevent transmission Sustained Outages and minimize risk to the Transmission System.
This approach provides the basis for evaluating the intent, allocation of appropriate resources and the competency of the Transmission Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid sustained outages. However, the Transmission Owner must be able to state what its approach is and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach a Transmission Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the Transmission Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

Conductor Dynamics
In order for a Transmission Owner to develop a specific maintenance approach, it is important to understand the dynamics of a line conductor's movement. This paper will first address the

complexities inherent in observing and predicting conductor movement, particularly for field personnel. It will then present some examples of maintenance approaches which Transmission Owners may consider that take into account these complexities, while resulting in practical approaches for field personnel.

Additionally, it is important the Transmission Owner consider all conductor locations, the MVCD, and vegetation growth between maintenance activities when developing a maintenance approach.

Understanding Conductor Position and Movement

The conductor's position in space at any point in time is continuously changing as a reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading.

As a consequence of these loading variables, the conductor's position in space is dynamic and moving. When calculating the range of conductor positions, the Transmission Owner should use the same design criteria and assumptions that the Transmission Owner uses when establishing Ratings and SOL, as described in other standards. Typically, the greatest conductor movement would be at mid-span. As the conductor moves through various positions, a spark-over zone surrounding the conductor moves with it. The radius of the spark-over zone may be found by referring to Table 1 ("Minimum Vegetation Clearance Distances") in the standard. For illustrations of this zone and conductor movements, Figures 4 through 6 below demonstrate these concepts. At the time of making a field observation, however, it is very difficult to precisely know where the conductor is in relation to its wide range of all possible positions. Therefore, Transmission Owners must adopt maintenance approaches that account for this dynamic situation.

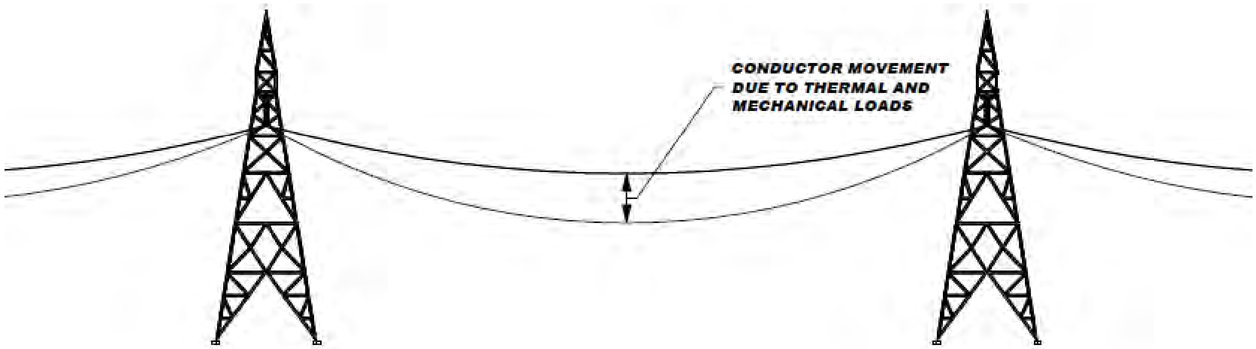

Figure 4

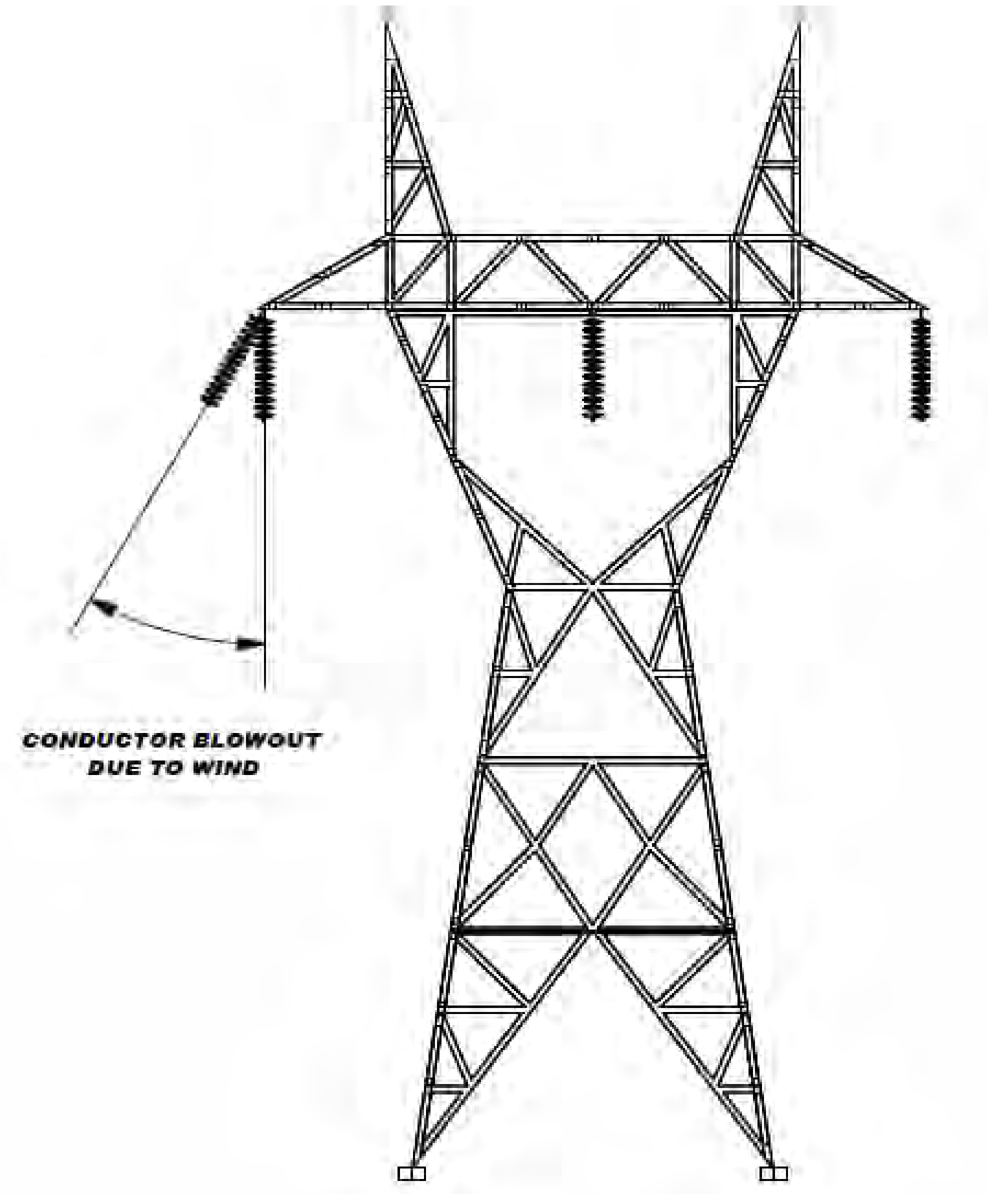

Figure 5

Cross-Section View of a Single Conductor
At a Given Point Along The Span
Showing Six Possible Conductor Positions Due to Movement
Resulting From Thermal and Mechanical Loading
For Consideration in Developing a Maintenance Approach

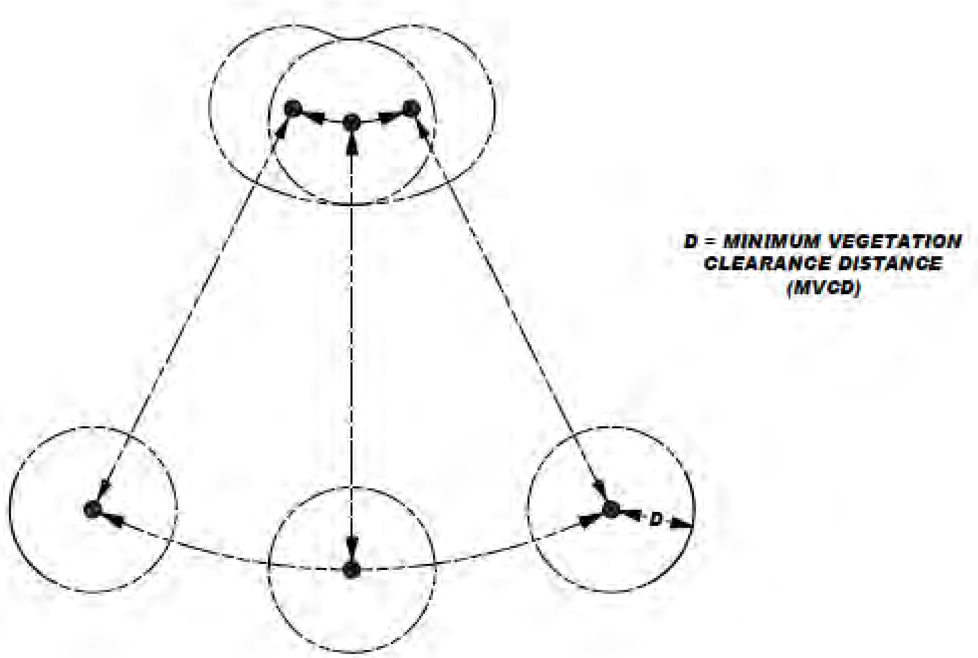

Figure 6

Selecting a Maintenance Approach

In order to maintain adequate separation between vegetation and transmission line conductors, the Transmission Owner must craft a maintenance strategy that keeps vegetation well away from the spark-over zone mentioned above. In fact, it is generally necessary to incorporate a variety of maintenance strategies. For example, one Transmission Owner may utilize a combination of routine cycles, traditional IVM techniques and long-term planning. Another Transmission Owner may place a higher reliance on frequent inspections and quick remediation as opposed to a cyclical approach. This variation of approaches is further warranted when factors, such as terrain, legal and other constraints, vegetation types, and climates, are considered in developing a Transmission Owner's specific approach to satisfying this requirement.

The following is a sample description of one combination of strategies which may be utilized by a Transmission Owner.

A Transmission Owner's basic maintenance approach could be to remove all incompatible vegetation from the right of way if it has the right to do so and has no constraints. In mountainous terrain, however, this strategy could change to one where the Transmission Owner manages vegetation based on vegetation-to-conductor clearances, since it might not be necessary to remove vegetation in a valley that is far below.

If faced with constraints and assuming a line design with sufficient ground clearance, the Transmission Owner 's approach could then be to allow vegetation such as fruit trees, but perhaps only up to a given height at maturity (perhaps 10 feet from the ground). If constraints cannot be overcome and if design clearances are sufficient, an exception to the Transmission Owner's 10-foot guideline might be made. Finally, if the Transmission Owner has chosen to utilize vegetation-to-conductor clearance distance methods, the Transmission Owner could have an inspection regimen in place to regularly ensure that any impending clearance problems are identified early for rectification.

ANSI A300 – Best Management Practices for Tree Care Operations

A description of ANSI A-300, part 7, is offered below to illustrate another maintenance approach that could be used in developing a comprehensive transmission vegetation management program.

Introduction

Integrated Vegetation Management (IVM) is a best management practice conveyed in the American National Standard for Tree Care Operations, Part 7 (ANSI 2006) and the International Society of Arboriculture Best Management Practices: Integrated Vegetation Management (Miller 2007). IVM is consistent with the requirements in FAC-003-02, and it provides practitioners with what industry experts consider to be appropriate techniques to apply to electric right-of-way projects in order to meet or exceed the Standard.

IVM is a system of managing plant communities whereby managers set objectives; identify compatible and incompatible vegetation; consider action thresholds; and evaluate, select and implement the most appropriate control method or methods to achieve set objectives. The choice of control method or methods should be based on the environmental impact and anticipated effectiveness; along with site characteristics, security, economics, current land use and other factors.

Planning and Implementation
Best management practices provide a systematic way of planning and implementing a vegetation management program. While designed primarily with transmission systems in mind, it is also applicable to distribution projects. As presented in ANSI A300 part 7 and the ISA best management practices, IVM consists of 6 elements:

1) Set Objectives
2) Evaluate the Site
3) Define Action Thresholds
4) Evaluate and Select Control Methods
5) Implement IVM
6) Monitor Treatment and Quality Assurance

The setting of objectives, defining action thresholds, and evaluating and selecting control methods all require decisions. The planning and implementation process is cyclical and continuous, because vegetation is dynamic and managers must have the flexibility to adjust their plans. Adjustments may be made at each stage as new information becomes available and circumstances evolve.

Set Objectives
Objectives should be clearly defined and documented. Examples of objectives can include promoting safety, preventing sustained outages caused by vegetation growing into electric facilities, maintaining regulatory compliance, protecting structures and security, restoring electric service during emergencies, maintaining access and clear lines of sight, protecting the environment, and facilitating cost effectiveness.

Objectives should be based on site factors, such as workload and vegetation type, in addition to human, equipment and financial resources. They will vary from utility to utility and project to project, depending on line voltage and criticality, as well as topographical, environmental, fiscal and political considerations. However, where it is appropriate, the overriding focus should be on environmentally-sound, cost effective control of species that potentially conflict with the electric facility, while promoting compatible, early successional, sustainable plant communities.

Work Load Evaluations
Work-load evaluations are inventories of vegetation that could have a bearing on management objectives. Work load assessments can capture a variety of vegetation characteristics, such as location, height, species, size and condition, hazard status, density and clearance from conductors. Assessments should be conducted considering voltage, conductor sag from ambient temperatures and loading, and the potential influence of wind on line sway.

Evaluate and Select Control Methods

Control methods are the process through which managers achieve objectives. The most suitable control method best achieves management objectives at a particular site. Many cases call for a combination of methods. Managers have a variety of controls from which to choose, including manual, mechanical, herbicide and tree growth regulators, biological, and cultural options.

Manual Control Methods

Manual methods employ workers with hand-carried tools, including chainsaws, handsaws, pruning shears and other devices to control incompatible vegetation. The advantage of manual techniques is that they are selective and can be used where others may not be. On the other hand, manual techniques can be inefficient and expensive compared to other methods.

Mechanical Control Methods

Mechanical controls are done with machines. They are efficient and cost effective, particularly for clearing dense vegetation during initial establishment, or reclaiming neglected or overgrown right of way. On the other hand, mechanical control methods can be non-selective and disturb sensitive sites.

Tree Growth Regulator and Herbicide Control Methods

Tree growth regulators and herbicides can be effective for vegetation management. Tree growth regulators (TGRs) are designed to reduce growth rates by interfering with natural plant processes. TGRs can be helpful where removals are prohibited or impractical by reducing the growth rates of some fast-growing species.

Herbicides control plants by interfering with specific botanical biochemical pathways. Herbicide use can control individual plants that are prone to re-sprout or sucker after removal. When trees that re-sprout or sucker are removed without herbicide treatment, dense thickets develop, impeding access, swelling workloads, increasing costs, blocking lines-of-site, and deteriorating wildlife habitat. Treating suckering plants allows early successional, compatible species to dominate the right-of-way and out-compete incompatible species, ultimately reducing work.

Cultural Control Methods

Cultural methods modify habitat to discourage incompatible vegetation and establish and manage desirable, early successional plant communities. Cultural methods take advantage of seed banks of native, compatible species lying dormant on site. In the long run, cultural control is the most desirable method where it is applicable.

A cultural control known as cover-type conversion provides a competitive advantage to short-growing, early successional plants, allowing them to thrive and eventually out-compete unwanted tree species for sunlight, essential elements and water. The early successional plant community is relatively stable, tree-resistant and reduces the amount of work, including herbicide application, with each successive treatment.

Wire-Border Zone

The wire-border zone technique is a management philosophy that can be applied through cultural control. W.C. Bramble and W.R. Byrnes developed it in the mid-1980s out of research begun in 1952 on a transmission right-of-way in the Pennsylvania State Game Lands 33 Research and Demonstration project (Yahner and Hutnik (2004).

The wire zone is the section of a utility transmission right-of-way directly under the wires and extending outward about 10 feet on each side. The wire zone is managed to promote a low-growing plant community dominated by grasses, herbs and small shrubs (under 3 feet in height at maturity). The border zone is the remainder of the right-of-way. It is managed to establish small trees and tall shrubs (under 25 feet in height at maturity). When properly managed, diverse, tree-resistant plant communities develop in wire and border zones. The communities not only protect the electric facility and reduce long-term maintenance, but also enhance wildlife habitat, forest ecology and aesthetic values.

Although the wire-border zone is a best practice in many instances, it is not necessarily universally suitable. For example, standard wire-border zone prescriptions may be unnecessary where lines are high off the ground, such as across low valleys or canyons, so the technique can be modified without sacrificing reliability.

One way to accommodate variances in topography is to establish different regions based on wire height. For example, over canyon bottoms or other areas where conductors are 100 feet or more above the ground, only a few trees are likely to be tall enough to conflict with the lines. In those cases, trees that potentially interfere with the transmission lines can be removed selectively on a case-by-case basis.

In areas where the wire is lower, perhaps between 50-100 feet from the ground, a border zone community can be developed throughout the right-of-way. Note that in many cases, conductor attachment points are more than 50 feet off the ground, so a border zone community can be cultivated near structures. Where the line is less than 50 feet off the ground, managers could apply a full wire-border zone prescription.

An environmental advantage of this type of modification is stream protection. Streams often course through the valleys and canyons where lines are likely to be elevated. Leaving timber or border zone communities in canyon bottoms helps shelter this valuable habitat, enabling managers to achieve environmentally sensitive objectives.

Implement IVM

All laws and regulations governing IVM practices and specifications written by qualified vegetation managers must be followed. Integrated vegetation management control methods should be implemented on regular work schedules, which are based on established objectives and completed assessments. Work should progress systematically, using control measures determined to be best for varying conditions at specific locations along a right-of-way. Some considerations used in developing schedules include the importance and type of line, vegetation clearances, work loads, growth rate of predominant vegetation, geography, accessibility, and in some cases, time lapsed since the last scheduled work.

Clearances Following Work
Clearances following work should be sufficient to meet management objectives, including preventing trees from entering the Minimum Vegetation Clearance Distance, electric safety risks, service-reliability threats and cost.

Monitor Treatment and Quality Assurance
An effective program includes documented processes to evaluate results. Evaluations can involve quality assurance while work is underway and after it is completed. Monitoring for quality assurance should begin early to correct any possible miscommunication or misunderstanding on the part of crewmembers. Early and consistent observation and evaluation also provides an opportunity to modify the plan, if need be, in time for a successful outcome.

Utility vegetation management programs should have systems and procedures in place for documenting and verifying that vegetation management work was completed to specifications. Post-control reviews can be comprehensive or based on a statistically representative sample. This final review points back to the first step and the planning process begins again.

Summary of A-300 example
Integrated Vegetation Management offers among others, a systematic way of planning and implementing a vegetation management program as presented in ANSI A300 Part 7. This methodology enables a program to comply with the NERC *Transmission Vegetation Management Program* standard (FAC-003-2). Managers should select control options to best promote management objectives.

Vegetation Inspections
As with the ANSI A-300 example, The Transmission Owner's transmission vegetation management program (TVMP) establishes the frequency of vegetation inspections based upon many factors. Such local and environmental factors may include anticipated growth rates of the local vegetation, length of the growing season for the geographical area, limited Active Transmission Rights of Way width, rainfall amounts, etc.

Annual Work Plan
Requirement R7 of the Standard addresses the execution of the annual work plan. A comprehensive approach that exercises the full extent of legal rights is superior to incremental management in the long term because it reduces overall encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient at all locations on the Active Transmission Line Right of Way. Removal is superior to pruning. Removal minimizes the possibility of conflicts between energized conductors and vegetation. Since this is not always possible, the Transmission Owner's approach should be to use its prescribed vegetation maintenance methods to work towards or achieve the maximum use of the Active Transmission Line Right of Way.

Requirement R4

R4. *Each Transmission Owner shall notify the responsible control center when it has verified knowledge of a vegetation imminent threat condition. A vegetation imminent threat condition is one which is likely to cause a Sustained Outage at any moment.*

The term "imminent threat" refers to a vegetation condition which is likely to cause a Sustained Outage at any moment. An imminent threat requires immediate action by the Transmission Owner to prevent the occurrence of a Sustained Outage.

> **Rationale**
> To ensure rapid notification of the correct personnel when an occurrence of a critical situation is observed. Verified knowledge includes observations by journeyman lineman, utility arborist, or other qualified personnel, or a report verified by these personnel.

M4. *Each Transmission Owner that has experienced a verified vegetation imminent threat will have evidence that it notified the responsible control center.*

R4 is a risk-based requirement type. It focuses upon preventative actions to be taken by the Transmission Owner for the mitigation of Sustained Outage risk when a vegetation imminent threat is verified. R4 involves the expeditious notification to the responsible control center of potentially threatening vegetation conditions to transmission lines.

The term "verified knowledge" implies reliable confirmation that an imminent threat actually exists due to vegetation. Verification could be that the initial call-in came from a trained employee able to identify such a threat or it could be verified by sending out such a trained person to confirm a call-in from a citizen or an untrained employee.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that presents an imminent danger of falling into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor operating between no-load and its rating.

The term "responsible control center" refers to personnel with direct responsibility for operating the transmission lines, such as the Transmission Owner's local control center, Transmission Operator, Independent System Operator, or other operating entity. In the case where the responsible control center is not the Transmission Operator, the communication between the responsible control center and the Transmission Operator will occur by the normal policies that govern their relationship.

The Transmission Owner has the responsibility to ensure the proper communication between field personnel and the responsible control center to allow the responsible control center to take the appropriate action until the threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service or positioning the system in recognition of the increasing risk of outage on that circuit.

The imminent threat notification should be communicated in terms of minutes or hours as opposed to a longer time frame for interim corrective action plans (see R5).
All potential grow-in or fall-in vegetation-related conditions are not necessarily considered imminent threats under this Standard. For example, some Transmission Owners may have a danger tree identification program that identifies tree for removal with the potential to fall near the line. These trees are not necessarily considered imminent threats under the Standard unless they pose an immediate fall-in threat.

Requirement R5

R5. *Each Transmission Owner shall take interim corrective action when it is temporarily constrained from performing planned vegetation work, where a transmission line is put at potential risk due to the constraint.*

M5. *Each Transmission Owner has evidence of the interim corrective action taken for each temporary constraint where a transmission line was put at potential risk. Examples of acceptable forms of evidence may include work orders, invoices, or inspection records.*

Rationale
Legal actions and other events may occur which result in constraints that prevent the Transmission Owner from performing planned vegetation maintenance work. When this event occurs and the work is essential to avoid risk to the transmission line the Transmission Owner must establish and act on a plan to prevent an imminent threat. This is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

R5 is a risk-based requirement type. It focuses upon preventative actions to be taken by the Transmission Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the Transmission Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the Transmission Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at immediate risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the Transmission Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the Transmission Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the Transmission Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for each location.
- In developing the specific action to mitigate the potential risk to the transmission line the Transmission Owner could consider location specific measures such as modifying

the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.

- The Transmission Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6

R6. *Each Transmission Owner shall perform a Vegetation Inspection of all applicable transmission lines at least once per calendar year*

M6. *Each Transmission Owner has evidence that it conducted Vegetation Inspections at least once per calendar year for applicable transmission lines. Examples of acceptable forms of evidence may include work orders, invoices, or inspection records.*

Rationale
The requirement is for once per calendar year because that seems to be reasonable length of time for a majority of situations. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections that may affect reliability.

R6 is a risk-based requirement type. It focuses upon the preventative action of vegetation inspections to be conducted by the Transmission Owner for the mitigation of Sustained Outage risk. This requirement sets a minimum vegetation inspection frequency of once per calendar year. A once per calendar year frequency is reasonable based upon average growth rates across North America and common utility practice. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections that may affect reliability.

This requirement sets a minimum time period for the Vegetation Inspections. More frequent inspections may be needed to maintain reliability levels, depending upon such factors as anticipated growth rates of the local vegetation, length of the growing season for the geographical area, limited Active Transmission ROW width, and rainfall amounts. Therefore some lines may be designated with a higher frequency of inspections.

The VSL for Requirement R6 has VSL categories ranked by the percentage of the required ROW inspections completed. To calculate the percentage of inspection completion, the Transmission Owner lines may choose units such as: line miles or kilometers, circuit miles or kilometers, pole line miles, ROW miles, etc.

For example, when a Transmission Owner operates 2,000 miles of 230 kV transmission lines this Transmission Owner will be responsible for inspecting all 2,000 miles of 230 kV transmission lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount inspected would be 1900/2000 = 0.95 or 95%. The “Lower VSL” for R6 would apply in this example.

The standard allows Vegetation Inspections to be performed in conjunction with general line inspections as per the definition.

Requirement R7

R7. *Each Transmission Owner shall execute a flexible annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD.*

M7. *Each Transmission Owner has evidence that it executed a flexible annual vegetation work plan. Examples of acceptable forms of evidence may include work orders, invoices, or inspection records.*

Rationale
This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. A flexible annual vegetation work plan allows for work to be deferred into the following calendar year provided it does not have the potential to become an imminent threat.

This is a risk-based requirement type. R7 focuses upon implementation of the annual vegetation work plan to diminish risk of vegetation encroachments within the MVCD. This requirement sets the expectation that the work identified in the annual vegetation work plan will be completed as planned.

The flexibility to adjust the annual vegetation work plan must always ensure the reliability of the electric Transmission system. Flexibility is meant to address changing conditions of the vegetation on the Active Transmission Line ROW, emergencies, and other significant changing conditions.

This standard requires that the annual vegetation work plan be flexible to allow the Transmission Owner to change priorities during the year as conditions or situations dictate. For example, weather conditions (drought) could make herbicide application ineffective during the plan year. Other conditions may also result in adjustments to the annual vegetation work plan:

- Environmental conditions such as excessive rainfall, infestation, disease, fire, etc.
- Work-management related conditions such as revised work plan priorities, rescheduled work to another time or selection of an alternative vegetation control method.
- Changes in land usage made by a property owner, such as timber clearing.
- Redirection of local resources away from planned maintenance to render assistance due to major storms, i.e., complying with mutual assistance agreements.

The work plan is not intended to be a “span-by-span” detailed description of all work to be performed. It is intended to require the Transmission Owner to annually plan and schedule vegetation work to prevent encroachment into the MVCD.

The Transmission Owner is required to implement the annual vegetation work plan to accomplish the purpose of this standard. This means that maintenance should be performed to the extent of the Transmission Owner’s easement, fee simple or other legal right. A comprehensive approach that exercises the full extent of legal rights is superior to incremental management in the long term by reducing overall encroachments. This approach emphasizes the importance of maintaining all locations on the Active Transmission Line ROWs for reliability purposes in lieu of making special exceptions.

Property owners, agencies and other interested parties occasionally request special considerations to leave undesirable vegetation conditions. Historically, such special considerations have led to outages (some of which became Cascading events) and can lead to violations of the standard.

Documentation or other evidence of the work performed typically consists of signed off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, work inspection reports and walk-through reports.

When the annual vegetation work plan is adjusted or otherwise not completely implemented as originally planned, the Transmission Owner is encouraged to document the change. The reasons for the deferrals or changes and the expected completion date of postponed work should also be documented.

When developing the annual vegetation work plan the Transmission Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Transmission Owners may also need to consider those special landowner requirements as documented in easement instruments.

Appendix One: Clearance Distance Derivation by the Gallet Equation

The Gallet Equation is a well-known method of computing the required strike distance for proper insulation coordination, and has the ability to take into account various air gap geometries, as well as non-standard atmospheric conditions. When the Gallet Equation and conservative probabilistic methods are combined, i.e. deterministic design, sparkover probabilities of 10^{-6} or less are achieved. This approach is well known for its conservatism and was used to design the first 500 kV and 765 kV lines in North America [1]. Thus, the deterministic design approach using the Gallet Equation is used for the standard to compute the minimum strike distance between transmission lines and the vegetation that may be present in or along the transmission corridor.

Method Explanation (Gallet Equation)

In 1975 G. Gallet published a benchmark paper that provided a method to compute the critical flashover voltage (CFO) of various air gap geometries [4]. The Gallet Equation uses various “gap factors” to take into account various air gap geometries. Various gap factor values are provided in [1]. If the vegetation in a transmission corridor, e.g. a tree, is assumed electrically to be a large structure then the CFO of such an air gap geometry can be computed for dry or wet conditions using a well established equation proposed by Gallet [1],[2],[4],

$$CFO_A = k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} \tag{1}$$

Where:

k_w is defined as the factor that takes into account wet or dry conditions (dry = 1.0 and wet = 0.96) and phase arrangement (multiply by 1.08 for outside phase), e.g. outside phase and wet conditions = (0.96)(1.08) = 1.037

k_g is defined as the gap factor (1.3 for conductor to large structure)

D is the strike distance (m)

CFO_A is the CFO for the relative air density (kV)

δ is defined as the relative air density and is approximately equal to (2) where A is the altitude in km

$$\delta = e^{-\frac{A}{8.6}} \tag{2}$$

$$m = 1.25G_0\left(G_0 - 0.2\right) \tag{3}$$

$$G_0 = \frac{CFO_s}{500 \cdot D} \tag{4}$$

$$CFO_s = k_w \cdot k_g \cdot \frac{3400}{1+\frac{8}{D}} \tag{5}$$

where CFO_S is the CFO for standard atmospheric conditions (kV). Using (1)-(5), the required CFO_A can be computed using an iterative process.

Once the CFO_A is known, deterministic methods can be used to determine the required clearance distance. If we let the maximum switching overvoltage be equal to the withstand voltage of the air gap (CFO_A - 3σ) then the CFO_A can be written as (6).

$$CFO_A = \frac{V_m}{1-3\left(\frac{\sigma}{CFO_A}\right)} \tag{6}$$

Where:

V_m is equal to the maximum switching overvoltage, i.e. the value that has a 0.135% chance of being exceeded

σ is the standard deviation of the air gap insulation

CFO_A is the critical flashover voltage of the air gap insulation under non-standard atmospheric conditions

The ratio of σ to the CFO_A given in (6) can be assumed to be 0.05 (5%) [1]. Thus, (6) can be written as (7).

$$CFO_A = \frac{V_m}{0.85} \tag{7}$$

Substituting (7) into (1) we arrive at (8).

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} \tag{8}$$

Equation 8 relates the maximum transient overvoltage, V_m, to the air gap distance, D. Using (8) to compute the required clearance distance for the specified air gap geometry (conductor to large structure) results in a probability of flashover in the range of 10^{-6}.

Transient Overvoltage

In general, the worst case transient overvoltages occurring on a transmission line are caused by energizing or re-energizing the line with the latter being the extreme case if trapped charge is present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to sparkover from the line conductor to nearby vegetation. Thus, the worst case scenarios that are typically analyzed for insulation coordination purposes (e.g. line energization and re-energization) can be ignored. For the purposes of FAC-003-2, the worst case transient overvoltage then becomes the maximum value that can occur with the line energized. Determining a realistic value of transient overvoltage for this situation is difficult because the maximum transient overvoltage factors listed in the literature are based on a

switching operation of the line in question. In other words, these maximum overvoltage values (e.g. the values listed in [2], [3] and [5]) are based on the assumption that the subject line is being energized, re-energized or de-energized. These operations, by their very nature, will create the largest transient overvoltages. Typical values of transient overvoltages of in-service lines, as such, are not readily available in the literature because the resulting level of overvoltage is negligible compared with the maximum (e.g. re-energizing a transmission line with trapped charge). A conservative value for the maximum transient overvoltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 p.u.[2]. This value is a conservative estimate of the transient overvoltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without a pre-insertion device (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. 362 kV), the maximum transient overvoltage of an “in-service” ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 p.u. or less [2]. It is well known that these theoretical transient overvoltages will not be experienced at locations remote from the bus at which they were created; however, in order to be conservative, it will be assumed that all nearby ac lines are subjected to this same level of overvoltage. Thus, a maximum transient overvoltage factor of 2.0 p.u. for 242 kV and below and 1.4 p.u. for ac transmission lines 362 kV and above is used to compute the required clearance distances for vegetation management purposes.

The overvoltage characteristics of dc transmission lines vary somewhat from their ac counterparts. The referenced empirically derived transient overvoltage factor used to calculate the minimum clearance distances from dc transmission lines to vegetation for the purpose of FAC-003-2 will be 1.8 p.u.[3].

Example Calculation

An example calculation is presented below using the proposed method of computing the vegetation clearance distances. It is assumed that the line in question has a maximum operating voltage of 550 kV_{rms} line-to-line. Using a per unit transient overvoltage factor of 1.4, the result is a peak transient voltage of 629 kV_{crest}. It is further assumed that the line in question operates at a maximum altitude of 7000 feet (2.134 km) above sea level.

The required withstand voltage of the air gap must be equal to or greater than 629 kV_{crest}. Since the altitude is above sea level, (1) - (5) have to be iterated on to achieve the desired result. Equation (9) can be used as an initial guess for the clearance distance.

$$D_i = \frac{8}{\dfrac{3400 \cdot k_w \cdot k_g}{\left(\dfrac{V_m}{0.85}\right)} - 1} \tag{9}$$

For our case here, V_m is equal to 629 kV, k_w = 1.037 and k_g = 1.3. Thus,

$$D_i = \frac{8}{\dfrac{3400 \cdot k_w \cdot k_g}{\left(\dfrac{V_m}{0.85}\right)} - 1} = \frac{8}{\dfrac{3400 \cdot 1.037 \cdot 1.3}{\left(\dfrac{629}{0.85}\right)} - 1} = 1.535m \tag{10}$$

Using (2)-(5) and (8) the withstand voltage of the air gap is next computed. This value will then be compared to the maximum transient overvoltage.

$$CFO_S = k_w \cdot k_g \cdot \frac{3400}{1+\frac{8}{D}} = 1.037 \cdot 1.3 \cdot \frac{3400}{1+\frac{8}{1.535}} = 737.7kV \qquad (11)$$

$$\delta = e^{-\frac{A}{8.6}} = e^{-\frac{2.134}{8.6}} = 0.78 \qquad (12)$$

$$G_O = \frac{CFO_S}{500 \cdot D} = \frac{737.7}{(500)\cdot(1.535)} = 0.961 \qquad (13)$$

$$m = 1.25 \cdot G_O (G_O - 0.2) = 1.25 \cdot 0.961(0.961 - 0.2) = 0.915 \qquad (14)$$

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} = (0.85)(1.037)(1.3)(0.78)^{0.915}\left(\frac{3400}{1+\frac{8}{1.535}}\right) = 499.8kV \qquad (15)$$

The calculated V_m is less than 629 kV; thus, the clearance distance must be increased. A few iterations using (2)-(5) and (8) are required until the computed $V_m \geq 629$ kV. For this case it was found that D = 1.978 m (6.49 feet) yielded V_m = 629.3 kV. Using this clearance distance the following values were computed for the final iteration.

$$CFO_S = k_w \cdot k_g \cdot \frac{3400}{1+\frac{8}{D}} = 1.037 \cdot 1.3 \cdot \frac{3400}{1+\frac{8}{1.978}} = 908.5kV \qquad (16)$$

$$\delta = e^{-\frac{A}{8.6}} = e^{-\frac{2.134}{8.6}} = 0.78 \qquad (17)$$

$$G_O = \frac{CFO_S}{500 \cdot D} = \frac{908.5}{(500)\cdot(1.978)} = 0.919 \qquad (18)$$

$$m = 1.25 \cdot G_O (G_O - 0.2) = 1.25 \cdot 0.919(0.919 - 0.2) = 0.825 \qquad (19)$$

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} = (0.85)(1.037)(1.3)(0.78)^{0.825}\left(\frac{3400}{1+\frac{8}{1.978}}\right) = 629.3kV \qquad (20)$$

Therefore, the minimum vegetation clearance distance for a maximum line to line ac operating voltage of 550 kV at 7000 feet above sea level is 1.978 m (6.49 feet). Table 1 provides calculated distances for various altitudes and maximum system operating ac voltages.

TABLE 1 — Minimum Vegetation Clearance Distances (MVCD)
For Alternating Current Voltages

(AC) Nominal System Voltage (kV)	(AC) Maximum System Voltage (kV)	MVCD feet (meters) Sea level	MVCD feet (meters) 3,000ft (914.4m)	MVCD feet (meters) 4,000ft (1219.2m)	MVCD feet (meters) 5,000ft (1524m)	MVCD feet (meters) 6,000ft (1828.8m)	MVCD feet (meters) 7,000ft (2133.6m)	MVCD feet (meters) 8,000ft (2438.4m)	MVCD feet (meters) 9,000ft (2743.2m)	MVCD feet (meters) 10,000ft (3048m)	MVCD feet (meters) 11,000ft (3352.8m)
765	800	8.06ft (2.46m)	8.89ft (2.71m)	9.17ft (2.80m)	9.45ft (2.88m)	9.73ft (2.97m)	10.01ft (3.05m)	10.29ft (3.14m)	10.57ft (3.22m)	10.85ft (3.31m)	11.13ft (3.39m)
500	550	5.06ft (1.54m)	5.66ft (1.73m)	5.86ft (1.79m)	6.07ft (1.85m)	6.28ft (1.91m)	6.49ft (1.98m)	6.7ft (2.04m)	6.92ft (2.11m)	7.13ft (2.17m)	7.35ft (2.24m)
345	362	3.12ft (0.95m)	3.53ft (1.08m)	3.67ft (1.12m)	3.82ft (1.16m)	3.97ft (1.21m)	4.12ft (1.26m)	4.27ft (1.30m)	4.43ft (1.35m)	4.58ft (1.40m)	4.74ft (1.44m)
230	242	2.97ft (0.91m)	3.36ft (1.02m)	3.49ft (1.06m)	3.63ft (1.11m)	3.78ft (1.15m)	3.92ft (1.19m)	4.07ft (1.24m)	4.22ft (1.29m)	4.37ft (1.33m)	4.53ft (1.38m)
161*	169	2ft (0.61m)	2.28ft (0.69m)	2.38ft (0.73m)	2.48ft (0.76m)	2.58ft (0.79m)	2.69ft (0.82m)	2.8ft (0.85m)	2.91ft (0.89m)	3.03ft (0.92m)	3.14ft (0.96m)
138*	145	1.7ft (0.52m)	1.94ft (0.59m)	2.03ft (0.62m)	2.12ft (0.65m)	2.21ft (0.67m)	2.3ft (0.70m)	2.4ft (0.73m)	2.49ft (0.76m)	2.59ft (0.79m)	2.7ft (0.82m)
115*	121	1.41ft (0.43m)	1.61ft (0.49m)	1.68ft (0.51m)	1.75ft (0.53m)	1.83ft (0.56m)	1.91ft (0.58m)	1.99ft (0.61m)	2.07ft (0.63m)	2.16ft (0.66m)	2.25ft (0.69m)
88*	100	1.15ft (0.35m)	1.32ft (0.40m)	1.38ft (0.42m)	1.44ft (0.44m)	1.5ft (0.46m)	1.57ft (0.48m)	1.64ft (0.50m)	1.71ft (0.52m)	1.78ft (0.54m)	1.86ft (0.57m)
69*	72	0.82ft (0.25m)	0.94ft (0.29m)	0.99ft (0.30m)	1.03ft (0.31m)	1.08ft (0.33m)	1.13ft (0.34m)	1.18ft (0.36m)	1.23ft (0.37m)	1.28ft (0.39m)	1.34ft (0.41m)

*As designated by the Planning Coordinator

TABLE 1 (CONT.) — Minimum Vegetation Clearance Distances (MVCD)
For **Direct Current** Voltages

(DC) Nominal Pole to Ground Voltage (kV)	MVCD feet (meters) sea level	MVCD feet (meters) 3,000ft (914.4m) Alt.	MVCD feet (meters) 4,000ft (1219.2m) Alt.	MVCD feet (meters) 5,000ft (1524m) Alt.	MVCD feet (meters) 6,000ft (1828.8m) Alt.	MVCD feet (meters) 7,000ft (2133.6m) Alt.	MVCD feet (meters) (8,000ft (2438.4m) Alt.	MVCD feet (meters) 9,000ft (2743.2m) Alt.	MVCD feet (meters) 10,000ft (3048m) Alt.	MVCD feet (meters) 11,000ft (3352.8m) Alt.
±750	13.92ft (4.24m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.9ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.07ft (3.07m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	(13.54ft 4.13m)
±500	7.89ft (2.40m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	4.78ft (1.46m)	5.35ft (1.63m)	5.55ft (1.69m)	5.75ft (1.75m)	5.95ft (1.81m)	6.15ft (1.87m)	6.36ft (1.94m)	6.57ft (2.00m)	6.77ft (2.06m)	6.98ft (2.13m)
±250	3.43ft (1.05m)	4.02ft (1.23m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5ft (1.52m)	5.17ft (1.58m)

List of Acronyms and Abbreviations

ANSI	American National Standards Institute
IEEE	Institute of Electrical and Electronics Engineers
IVM	Integrated Vegetation Management
NERC	North American Electric Reliability Corporation

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NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Informal Comment Period Open

March 1–31, 2010

Now available at: http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

Project 2007-07: Transmission Vegetation Management

The Transmission Vegetation Management Standard Drafting Team is seeking comments on the following documents **until 8 p.m. Eastern on March 31, 2010**:

- FAC-003-2 — Transmission Vegetation Management Program
- Mapping document (comparing this draft to previous)
- Implementation plan

Special Notes for this Project

On January 14, 2010, the NERC Standards Committee endorsed the selection of FAC-003 as the proof-of-concept for using “results-based” criteria for developing a reliability standard, and the drafting team has been working with a consultant to apply a results-based approach to draft standard FAC-003-2. The overall approach includes considerably more emphasis on the “concepts and assumptions” underlying the development of requirements and goes beyond the steps most drafting teams use when developing a standard. Accordingly, the “look and feel” of the vegetation management standard is quite different than NERC’s existing standards. However, at the core is a set of mandatory and enforceable requirements with useful guidance supporting these requirements, an approach NERC’s legal counsel has reviewed and finds acceptable.

In addition to the format changes, the Standards Committee authorized the drafting team to discontinue work in developing a complete consideration of comments report for the comments received in response to the posting of the second draft of FAC-003-2 (August 2009). Instead of posting an individual response to each comment, the team has posted the comments along with a summary of the actions taken by the team in response to those comments. The Standards Committee also authorized this approach going forward for this project, so this and future postings will be considered informal comment periods. Please see the “Next Steps” section below and the comment form for more information.

Instructions

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at Lauren.Koller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page:
http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

Next Steps

Since this is an informal comment period, the drafting team will post 1) the comments received, 2) a summary of how the team used the comments, and 3) a redline version of the standard showing the changes made based on the comments. More information about the scheduling for this project is available in the comment form for this posting.

Project Background

The project is an update to FAC-003-1, which was approved in 2006. The items identified for revision include the incorporation of FERC Order 693 comments related to applicability, procedural repairs to conform to the current standards format and development procedure, technical updates and guidance to address stakeholder suggestions, and the elimination of “fill-in-the-blank” components. More information is available on the project page:
http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

As mentioned, the NERC Standards Committee endorsed the use of Project 2007-07 Vegetation Management as the prototype for the proof-of-concept for using the “results-based” criteria for developing a reliability standard. More information about results-based standards can be found at:
http://www.nerc.com/filez/standards/Project2010-06_Results-based_Reliability_Standards.html

Applicability of Standards in Project

Transmission Owner
Specific facilities (see proposed standard for more information)

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Consideration of Comments on 3rd Draft of FAC-003-2 Transmission Vegetation Management — Part of Project 2007-07 Vegetation Management

The Vegetation Management Standard Drafting Team thanks all commenters who submitted comments on the 3rd Draft of FAC-003-2 Transmission Vegetation Management. These standards were posted for a 30-day public comment period from March 1, 2010 through March 31, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 55 sets of comments, including comments from more than 100 different people from over 60 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Ben Eng	New York Power Authority	NPCC	4
7.	Brian Evans-Mongeon	Utility Services	NPCC	8
8.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
9.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Michael R. Lombardi	Northeast Utilities	NPCC	1
12.	Randy MacDonald	New Brunswick System Operator	NPCC	2
13.	Greg Mason	Dynegy Generation	NPCC	5
14.	Bruce Metruck	New York Power Authority	NPCC	6
15.	Michael Schiavone	National Grid	NPCC	1

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
16.	Lee Pedowicz		Northeast Power Coordinating Council	NPCC						10			
17.	Robert Pellegrini		The United Illuminating Company	NPCC						1			
2.	Group	Jim Case	SERC OC Standards Review Group	X		X							
	Additional Member		Additional Organization	Region						Segment Selection			
1.	Gerald Beckerle		Ameren	SERC						1, 3			
2.	Alvis lanton		Southern Illinois Power Cooperative	SERC						1, 3, 5			
3.	Melinda Montgomery		Entergy	SERC						1, 3			
4.	Ken Parker		Entegra	SERC						5			
5.	Larry Rodriquez		Entegra	SERC						5			
6.	Gwen Frazier		Gulf Power	SERC						1, 3, 5			
7.	Stephen Mizelle		Southern	SERC						1, 3, 5			
8.	Brad Young		E.ON.US	SERC						1, 3, 5			
9.	John Troha		SERC	SERC						10			
3.	Group	Louis Slade	Dominion	X		X		X	X				
	Additional Member		Additional Organization	Region						Segment Selection			
1.	Jalal Babik		Electric Market Policy	SERC						6, 5			
2.	Mike Garton		Electric Market Policy	MRO						6, 5			
3.	John Loftis		NERC compliance	SERC						1, 3			
4.	Angela Park		NERC compliance	SERC						1, 3			
5.	Aaron Jonas		Forestry	SERC						1			
4.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee										X
	Additional Member		Additional Organization	Region						Segment Selection			
1.	Chuck Lawrence		American Transmission Company	MRO						1			
2.	Tom Webb		Wisconsin Public Service Company	MRO						3, 4, 5, 6			
3.	Terry Bilke		Midwest ISO Inc.	MRO						2			
4.	Jodi Jenson		Western Area Power Administration	MRO						1, 6			
5.	Ken Goldsmith		Alliant Energy	MRO						4			
6.	Dave Rudolph		Basin Electric Power Cooperative	MRO						1, 3, 5, 6			

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Eric Ruskamp		Lincoln Electric System	MRO						1, 3, 5, 6			
8.	Joseph Knight		Great River Energy	MRO						1, 3, 5, 6			
9.	Joe DePoorter		Madison Gas & Electric	MRO						3, 4, 5, 6			
10.	Scott Nickels		Rochester Public Utilties	MRO						4			
11.	Terry Harbour		MidAmerican Energy Company	MRO						1, 3, 5, 6			
5.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				
	Additional Member		Additional Organization	Region						Segment Selection			
1.	Chuck Sheppard		BPA Transmission Field Services	WECC						1			
2.	Don Swanson		BPA Transmission Line Maintenance	WECC						1			
6.	Group	Joe Spencer (SERC staff) and Jack Gardner (VMS chair)	SERC Vegetation Management Sub-committee										X
	Additional Member		Additional Organization	Region						Segment Selection			
1.	Randy Gann		Alabama Power Company	SERC									
2.	Gerald Beckerle		Ameren Services Company	SERC									
3.	Jeffrey Hackman		Ameren Services Company	SERC									
4.	John Neagle		Associated Electric Cooperative, Inc.	SERC									
5.	Billy George		Duke Energy Carolinas	SERC									
6.	Ron Adams		Duke Energy Carolinas	SERC									
7.	Robert Trimble		E.ON U.S. Services Inc. for LG&E & KU	SERC									
8.	Jim Case		Entergy	SERC									
9.	Ralph Hale		Entergy	SERC									
10.	Marc Tunstall		Fayetteville Public Works Commission	SERC									
11.	Reggie Wallace		Fayetteville Public Works Commission	SERC									
12.	Terry Wilson		PowerSouth Energy Cooperative	SERC									
13.	Jack Gardner		Progress Energy Carolinas	SERC									
14.	John Wolfmeyer		SERC Reliability Corporation	SERC									
15.	Jerry Lindler		South Carolina Electric & Gas Company	SERC									
16.	Richard Dearman		Tennessee Valley Authority	SERC									

		Commenter	Organization	Industry Segment 1	2	3	4	5	6	7	8	9	10
7.	Group	Ben Li	IRC Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Phillips	MISO	MRO	2
2.	James Castle	NYISO	NPCC	2
3.	Charles Yeung	SPP	SPP	2
4.	Matt Goldberg	ISO-NE	NPCC	2
5.	Mark Thompson	AESO	WECC	2
6.	Patrick Brown	PJM	RFC	2
7.	Steve Myers	ERCOT	ERCOT	2

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Richard Kafka	Pepco Holdings, Inc. - Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Pat Byrne	Pepco Holdings, Inc	RFC	1
2.	Dave Paduda	Potojmac Electric Power Company	RFC	1
3.	Steve Benn	Delmarva Power & Light	RFC	1
4.	Olivia Watts	Atlantic City Electric	RFC	1
5.	Steve Genua	Pepco Holdings, Inc	RFC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rebecca Spach	FE	RFC	1
2.	Katrina Schnobrich	FE	RFC	1
3.	Dave Folk	FE	RFC	1, 3, 4, 5, 6
4.	Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Carter B. Edge	Ad Hoc Group subteam formed to review draft standard										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Peter Heidrich	FRCC	FRCC	
2.	Pat Huntley	SERC	SERC	
3.	Roman Carter	NERC	NA - Not Applicable	

Additional Member	Additional Organization	Region	Segment Selection
4. Steve Ruekert	WECC	WECC	
5. Chris Hajovsky	RRI Energy	NA - Not Applicable	

		Commenter	Organization	Industry Segment 1	2	3	4	5	6	7	8	9	10
11.	Group	Frank Gaffney	Florida Municipal Power Agency (FMPA) and Some Members	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Tim Byerle	New Smyrna Beach	FRCC	1, 3, 4
2. Jim Howard	Lakeland Electric	FRCC	1, 3, 5
3. Greg Woessner	Kissimmee Utilities Authority	FRCC	1, 3, 5
4. Lynne Mila	Clewiston	FRCC	1, 3, 4
5. Joe Stonecipher	Beaches Energy Services	FRCC	1, 3, 4
6. Cairo Venegas	Fort Pierce Utilities Authority	FRCC	1, 3, 4, 5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Individual	Thomas Glock	Arizona Public Service Company			X		X	X				
13.	Individual	Chip Turner	Tampa Electric Company	X		X		X	X				
14.	Individual	Stephen Mizelle	Southen Company	X									
15.	Individual	Silvia Parada Mitchell	TO/TOP	X		X		X	X				
16.	Individual	John Buckley	Omaha Public Power District	X				X					
17.	Individual	Howard Gugel	NERC Staff (12 staff members)										
18.	Individual	Gary Cox	Tucson Electric Power Co.	X									
19.	Individual	Edward Bedder	Orange and Rockland Utilities, Inc.	X		X							
20.	Individual	Greg Lange	GCPD				X						
21.	Individual	Christopher M. Crane	Westchester County Board of Legislators									X	
22.	Individual	Robert Beadle	North Carolina EMC			X	X	X					
23.	Individual	Mary Hetz	Ameren	X									
24.	Individual	James W. Smith	ITC Holding	X									
25.	Individual	Alan Gale	City of Tallahassee (TAL)					X					

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
26.	Individual	Virginia Cook	JEA	X		X		X					
27.	Individual	Weston Davis	Central Maine Power, Iberdrola USA	X									
28.	Individual	Eric Senkowicz	FRCC Manager of Operations										X
29.	Individual	Samuel Stonerock	Southern California Edison Company	X		X		X	X				
30.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				
31.	Individual	Chris Scanlon	Exelon	X		X		X	X				
32.	Individual	Jody Nelson	Ga Transmission Corp	X									
33.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
34.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
35.	Individual	Laura Zotter	ERCOT ISO		X								X
36.	Individual	Gerald T. Paulson	Western Area Power Administration - Upper Great Plains Region	X									
37.	Individual	Louis C. Guidry	Cleco	X		X		X	X				
38.	Individual	Tom Hayes	East Kentucky Power Cooperative, Inc.	X		X		X					
39.	Individual	Jack Gardner	Progress Energy Carolinas	X		X		X	X				
40.	Individual	Kevin Howard	Western Area Power Administrtaion	X								X	
41.	Individual	James Sharpe	South Carolina Electric and Gas	X		X		X	X				
42.	Individual	George Czerniewski	Consolidated Edison Company of New York, Inc.	X									
43.	Individual	Michael Pakeltis	CenterPoint Energy	X									
44.	Individual	Darryl Curtis	Oncor Electric Delivery	X									
45.	Individual	Thad Ness	American Electric Power (AEP)	X		X		X	X				
46.	Individual	Dan Rochester	Independent Electricity System Operator		X								
47.	Individual	Richard Dearman	Tennessee Valley Authority	X		X		X					

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
48.	Individual	Jim Fulton	BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	X									
49.	Individual	Edward Davis	Entergy Services	X		X		X	X				
50.	Individual	Jason Shaver	American Transmission Company	X									
51.	Individual	David Rocchio	Utility Risk Management Corporation										
52.	Individual	Earl Burnside	PPL Electric Utilities Corporation (NCR00884)	X		X							
53.	Individual	Jianmei Chai	Consumers Energy			X	X	X					
54.	Individual	John Humphrey	Nebraska Public Power District	X		X		X					
55.	Individual	Christopher M. Crane	Westchester County Board of Legislators										
56.	Individual	Mike Gammon	KCPL										

1. In response to comments received regarding potential for "double jeopardy" and to provide differentiation between transmission lines designated as having IROLs and Major WECC transfer paths from those that are not, the SDT consolidated requirements R4 though R8 found in the August 2009 draft of FAC-003-2 into two requirements in the latest draft of FAC-003-2 (new requirements R1 and R2). Do you agree? Please explain.

Summary Consideration:

Organization	Yes or No	Question 1 Comment
ERCOT ISO		
Exelon		
North Carolina EMC		
Westchester County Board of Legislators		Do not have enough knowledge on this to provide response.
Response:		
Nebraska Public Power District	No	Although it does provide some flexibility to the TO, it will be difficult to determine an encroachment into the MVCD. It would easier to implement if R1 and R2 were only applicable when there was an outage on the transmission system.
Response:		
Dominion	No	Dominion does not agree with the inclusion of facilities that WECC designates as 'major transfer paths' in a continent-wide standard. We suggest that, if the SDT wishes to include such reference and these facilities are meant to be treated or synonymous with either IROL or SOL, that the SDT add a proposal to adopt and define a suitable term for inclusion into the Glossary of Terms
Response:		
Cleco	No	Encroachment into the MCVD should require the owner to take immediate corrective action to mitigate the threat. Such an encroachment should not be reportable as a violation. Owners may be hesitant to

Organization	Yes or No	Question 1 Comment
		communicate possible vegetation threat conditions to the TOP or proper authority if they believe it will be reported as a violation. We recommend the SDT consider modifying the measure for R1 and R2 to be applicable only in the interruption of the transmission facility.
Response:		
NERC Staff (12 staff members)	No	NERC Staff does not see a need to have two requirements (R1 and R2) which differentiation between transmission lines designated as having IROLs and Major WECC transfer paths from those that are not with two different Violation Risk Factors. The standard as drafted applies to all 200kv and above lines. The Violation Risk Factor for all 200 kV and above lines should be "High". R2 should be deleted and R1 should be rewritten to be:R1. The Transmission Owner shall prevent vegetation from encroaching within the Minimum Vegetation Clearance Distance (MVCD) of applicable Transmission line conductors to avoid a Sustained Outage.
Response:		
Xcel Energy	No	Requirements 1 & 2 are identical except for their applicability (R1 for IROL elements and elements in the WECC Transfer Paths; R2 for all other lines =>200 KV). It is not readily apparent as to why there is a need to distinguish between the two. Referencing the Table 2 "VRF" and "VSL" matrix indicates that R1 has a "High" VRF and R2 has a "Medium" VRF. If this is the only reason, then consider adding, at a minimum, a "Rationale" box explaining that reasoning.Also, the definition of MVCD needs to be a defined term or included in R 1 & 2, e.g., "Minimum Vegetation Clearance Distance is the calculated minimum distanced stated in feet (meters) to prevent spark-over between conductors and vegetation for various altitudes and operating voltages as set forth in Table 2." See comments to # 7 and # 13.
Response:		
Arizona Public Service Company	No	This is a reliability standard for 230 kV and above and those lower voltages designated by the RRO. An outage is an outage and the utility should be held accountable no matter if they are or are not designated.
Response:		
SERC OC Standards Review Group	No	While we agree with the development of a second requirement to provide for the distinction between line segments that are critical for reliability, in R1, a regional distinction should not be embedded in a national standard. We also strongly disagree that perfect compliance with R2, as stated, would improve reliability. If a line is operated to avoid projected post contingent overloads, then the tripping thereof due to any cause has

Organization	Yes or No	Question 1 Comment
		no effect on BES reliability. A more prudent approach for the lines covered by R2 could be the requirement to achieve 3 sigma or 4 sigma performance over a year's time. Requirement 2, as stated, is not cost effective, and may produce an unjust and unreasonable outcome to rate payers.While this draft clarifies (from version FAC-003-1) that sustained outages are compliance violations and eliminates the "double jeopardy" which was errantly introduced in the last draft of FAC-003-2 (when sustained outages were clearly defined as compliance violations), we suggest that the team adjust R2 as previously mentioned. This draft provides a mechanism to address the difference in outages that have impact to grid reliability from those that have an impact only to local lines and associated customer reliability. The use of observed MVCD as a violation and in the violation severity level matrix: o drives the right behaviors for improving reliability (by proactively identifying and removing vegetation before it can become an imminent threat or cause an outage) o eliminates the need to perform detail engineering/surveying/theoretical calculations before cutting vegetation, o formalizes the informal interpretations that have resulted from FAC-003-1 enforcement and o allows the vegetation field operations to focus on facts and remain practical rather than theoretical.
Response:		
American Transmission Company	Yes	
Bonneville Power Administration	Yes	
Central Maine Power, Iberdrola USA	Yes	
City of Tallahassee (TAL)	Yes	
Consumers Energy	Yes	
Duke Energy	Yes	
Florida Municipal Power Agency (FMPA) and Some Members	Yes	
FRCC Manager of Operations	Yes	

Organization	Yes or No	Question 1 Comment
Ga Transmission Corp	Yes	
GCPD	Yes	
ITC Holding	Yes	
Manitoba Hydro	Yes	
Omaha Public Power District	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	
Southen Company	Yes	
TO/TOP	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	
MRO's NERC Standards Review Subcommittee	Yes	1. NSRS agrees with the revisions that the drafting team has made and agrees with the combining of four requirements into two. NSRS prefers the MVCD methodology to the minimum clearance distance methodology due to the fact that there is only one measurement to contend with versus two.2. If a company has a line with a standing IROL could they be found in violation of both the requirements R1 and R2? If so, the NSRS recommends combining R1 and R2.3. Please clarify the need for R1 and R2. Why were lines with IROL separated out from lines without IROLs?
Response:		

Organization	Yes or No	Question 1 Comment
American Electric Power (AEP)	Yes	American Electric Power agrees with this change.
Response:		
IRC Standards Review Committee	Yes	Because real-time observation in Measurement 1 would require an actual measurement for comparison to Table 2 to be defendable as a violation, the SRC suggests replacing observation with measurement. The SRC would suggest deleting the phrase "to avoid a sustained outage" as that phrase does not add any clarity to either of the two requirements. There do not seem to be any encroachments that the SDT will allow. If there are encroachments that are considered allowable, who is responsible for making that consideration? And what would be considered a "sustained" outage?Minimum Vegetation Clearance Distance (MVCD) is a capitalized term used in Requirements 1, 2 and 7 but is not defined in the NERC Glossary of Terms Used in Reliability Standards nor is a definition proposed in this standards action. Either a definition should be proposed or the capitalization should be removed.
Response:		
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	BGE agrees with the consolidation of R4 through R8 into two requirements in the FAC-003-2 draft.
Response:		
Ameren	Yes	Creating two specific requirements removes the potential for double jeopardy.
Response:		
Southern California Edison Company	Yes	SCE agrees that the consolidation of Requirements R4-R* resolves the "double jeopardy" issue.
Response:		
Tampa Electric Company	Yes	The change in the draft serves to consolidate, clarify and remove the “double jeopardy” as stated above. This is an improvement in the standard.
Response:		

Organization	Yes or No	Question 1 Comment
CenterPoint Energy	Yes	The differentiation in the Violation Risk Factor for R1 versus R2 seems appropriate.
Response:		
Consolidated Edison Company of New York, Inc.	Yes	The elements that comprise IROLs must be clearly communicated to each Transmission Owner and must be consistent across North America.
Orange and Rockland Utilities, Inc.	Yes	The elements that comprise IROLs must be clearly communicated to each Transmission Owner and must be consistent across North America.
Response:		
Northeast Power Coordinating Council	Yes	The most recent draft of the standard consolidated R4-R8 results in clearer requirements that meet the results based criteria and addresses the “double jeopardy” issue. However, there is concern with the differentiation of lines designated as having IROLs and Major WECC transfer paths from those that are not, as is proposed in the Applicability section 4.2 and subsequently in requirements R1 and R2. As stated in the background section: “This Standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this Standard is not written to address such isolated situations which have little impact on the overall Bulk Electric System.” It must be recognized that in some systems, outages on lines operated at voltages greater than 69 kV, 200 kV for example, have localized impact only and do not lead to Cascading. Concurring with the background, a line should be subject to this standard only if a vegetation related outage “could lead to Cascading”, or could have a “significant impact” on the system. It does not depend on whether it is an IROL line or not.A performance based methodology is used in NPCC to determine if an outage on a line can cause a “significant impact” on the system. The lines identified by this methodology are not identified according to their voltages, but rather by their impact on the system, regardless of the voltage.The introduction of “two” subcategories of BES - an IROL and a non-IROL - appears to just differentiate between high VRF and medium VRF. Furthermore, in the Applicability section, the IROL “variable” is mentioned only for lines operated below 200 kV. What about lines operated at or above 200 kV lines? Why not have a single Application item stating: overhead transmission lines operated at any voltage whose outages have a significant impact on the system? A Table could define what is considered “significant”.There are standards for vegetation management on the distribution system, and there are standards for higher voltage systems. This standard should focus on lines with high impact on the system when a vegetation outage occurs.Utilities will not let the vegetation encroach on other lines, but an importance will be given to vegetation management

Organization	Yes or No	Question 1 Comment
		on "critical" lines for the reliability of the whole system. On other lines, if an outage occurs, it will have localized impact.A "Results-Based Reliability Standard" should first focus on the "critical" lines.If it is the intent of NERC or the industry to ensure that a vegetation outage causes no more than a fixed level of load loss, it should say so in a requirement.If the IROL "variable" is retained, identification of the transmission elements that comprise IROLs must be officially communicated to the Transmission Owners. This must be done either through a requirement in this, or another standard.
Response:		
Progress Energy Carolinas	Yes	The previous version (FAC-003-1) was not developed with individual outages listed as a requirement or a violation. The previous drafts of version 2 (FAC-003-2) have improved on FAC-003-1 by defining sustained outages from within the Right-of-Way as violations. However, the recent drafts of FAC-003-2 also introduced a potential for 'double jeopardy' when clarifying that sustained outages and MVCD encroachments were ('binary') requirements/violations. This latest draft clarifies the expected performance into two concise requirements that provide for differentiation in severity levels and risk factors, eliminating the unintended 'double jeopardy'. The inclusion of the use of observed MVCD as a violation of R1/R2 and in the violation severity level matrix drives the right behaviors for improving reliability (by proactively identifying and removing vegetation before it can become an imminent threat or cause an outage) , eliminates the need to perform detail engineering/surveying/theoretical calculations before cutting vegetation, formalizes the informal interpretations that have resulted from FAC-003-1 and allows the vegetation field operations to focus on facts (and remain practical rather than theoretical). Progress Energy believes that the R1 and R2 changes to this draft are a significant improvement over FAC-003-1. This version draft: clarifies real-time MVCD and sustained outages as a requirement; provides for differentiation between grid impacting outage events and outage events to lines primarily associated with customer reliability; introduces a performance barrier/defense that is fact based - eliminating the need to determine compliance through theoretical calculations that rely on design assumptions (e.g., mechanical behavior of aged conductor), prior design criteria/code versions (i.e., code clearances in effect at time of design) and detail site measurements (e.g., "survey" quality measurements and local environmental conditions at time of measurement/event).
Response:		
JEA	Yes	The simplification and clarification improves the ability of Registered Entities to comply thereby enhancing reliability.
Response:		

Organization	Yes or No	Question 1 Comment
Independent Electricity System Operator	Yes	This change addresses the perceived “double jeopardy” risk.
Response:		
Oncor Electric Delivery	Yes	This does not reduce the Standards effectiveness on the cascading issue or discount any outage on applicable lines subject to this Standard in the electric Transmission system.
Response:		
East Kentucky Power Cooperative, Inc.	Yes	This draft adequately addresses the "double jepoardy" issue. The use of the Minimum Vegetation Clearance Distances simplifies recommended maintenance process for field personnel and eliminates the need to perform costly and time consuming engineering studies prior to trimming or removing vegetation.
Response:		
SERC Vegetation Management Sub-committee	Yes	This draft clarifies (from version FAC-003-1) that sustained outages are compliance violations and eliminates the “double jeopardy” which was errantly introduced in the last draft of FAC-003-2 (when sustained outages were clearly defined as compliance violations). This draft provides a mechanism to address the difference in outages that have impact to grid reliability from those that have an impact only to local lines and associated customer reliability. The use of observed MVCD as a violation and in the violation severity level matrix: o drives the right behaviors for improving reliability (by proactively identifying and removing vegetation before it can become an imminent threat or cause an outage) o eliminates the need to perform detail engineering/surveying/theoretical calculations before cutting vegetation, o formalizes the informal interpretations that have resulted from FAC-003-1 enforcement and o allows the vegetation field operations to focus on facts and remain practical rather than theoretical.
Response:		
Western Area Power Administrtaion	Yes	This is a very efficient and logical consolidation of requirements.
Response:		
Western Area Power	Yes	This is not a critical issue for the WAPA - UGPR.

Organization	Yes or No	Question 1 Comment
Administration - Upper Great Plains Region		
Response:		
Tennessee Valley Authority	Yes	This method effectively recognizes the difference in reliabilty risks among various lines based on their value to the transmission grid.
Response:		
Entergy Services	Yes	We agree that R1 and R2 are beneficial, but believe that they should be explained in greater detail for much greater clarity to reflect their intent. Our understanding is that R1 applies to ALL IROL's and ALL Major WECC Transfer Path lines, regardless of voltage, and R2 is centered around ALL lines operated at voltages 200 kV and above but are not classified as IROL/WECC lines. Our understanding of the term "applicable line conductor" in R2 refers back to the facilities defined in Facilities - Section 4.2 and as modified by the phrase in R2: "which are not elements of an IROL and are not a Major WECC transfer path, (operating within Rating and Rated Electrical Operating Conditions)". However the appropriateness of our assumed reference back to Section 4.2 and the modification contained in R2 is not clear. It also is not clear that the term "applicable line conductor" in R2 is the same as "applicable line conductor" in R6. We suggest the term "applicable line conductor" be specifically defined as that term is intended to be applied in R2, and the term "applicable line conductor" be defined as that term is intended to be applied in R6.
Response:		
FirstEnergy	Yes	We agree that the new R1 and R2 alleviate the potential double jeopardy issue as well as differentiate the high and medium risk factor transmission lines. However, we offer the following comments and suggestions for improvement:It is not clear how the Transmission Owner (TO) will determine which lines are associated with IROLs. Upon reviewing standard FAC-014 Req. R5, which requires the communication of SOLs and IROLs, the required communication of IROLs to the TO is not specified. There needs to be a tie between this standard and the FAC-014 standard, which will require a revision to FAC-014. Unfortunately, this issue will create a gap if FAC-014 is not revised and submitted to FERC in parallel with the submittal of FAC-003-2 to FERC. This may require immediate action such as an urgent action SAR or other appropriate actions.If our suggestion to revise FAC-014 is not possible at the present time, then we suggest an alternative course of action to include language in R1 of FAC-003 to aid the TO in obtaining the information regarding lines associated with IROLs. We propose adding the following sentence to R1: "The Transmission Owner can request information regarding transmission lines associated with an IROL from its Planning Coordinator."

Organization	Yes or No	Question 1 Comment
Response:		
Ad Hoc Group subteam formed to review draft standard	Yes	We understand the differentiation to be around the intent that those transmission lines designated as having IROLs and Major WECC transfer paths pose a more significant threat to the reliability of the BES and that encroachment of the MVCD in these cases are relatively more significant. We suggest that this be clarified in the rationale.
Response:		
KCPL	No	The measures for R1 and R2 are zero tolerance for encroachments into the MVCD that did not result in a "contact" with the transmission facility. Considering the substantial number of miles of transmission involved, the complexities in anticipation of vegetation growth with numerous growth variables, vegetation management limitations imposed by other regulations or requirements, and unexpected transmission events that require substantial efforts regarding physical restoration, it is not reasonable or practical for the measures here to include encroachments that do not result in an interruption of transmission service. Recommend the SDT consider modifying the measures for R1 and R2 to be applicable only in the interruption of a transmission facility.
Response:		

2. The results-based reliability standard criteria focus on striving to achieve a portfolio of performance-based, risk-based, and competency-based mandatory reliability requirements that provide an effective defense-in-depth strategy for achieving an adequate level of reliability of the bulk power system in lieu of prescriptive requirements. Consequently, the SDT revised R1 and its subparts found in the August 2009 draft of FAC-003-2 in favor of the text in the latest draft of FAC-003-2 (new requirement R3). Do you agree? Please explain.

Summary Consideration:

Organization	Yes or No	Question 2 Comment
American Transmission Company		
East Kentucky Power Cooperative, Inc.		
ERCOT ISO		
Westchester County Board of Legislators		
Tampa Electric Company	No	A more in-depth technical review of this requirement is required. Our response is predicated upon the following quote from the draft standard; "...considering all possible locations the conductor may occupy assuming operation within Rating and Rated Electrical Operating Conditions."
Response:		
NERC Staff (12 staff members)	No	As written, R3 does not provide enough clarity as to what should be included in a documented transmission vegetation management program. R3 should be expanded to include what should be included in the transmission plan. Such as:R3. Each Transmission Owner shall have a documented transmission vegetation management program that describes how it conducts work on its Active Transmission Line Rights of Way to avoid Sustained Outages due to vegetation, considering all possible locations the conductor may occupy assuming operation within Rating and Rated Electrical Operating Conditions. The transmission vegetation management program shall:3.1 Specify the methodologies that the Transmission Owner uses to control vegetation.[1] 3.2 Specify a Vegetation Inspection frequency of at least once per calendar year that takes into account local[2] and environmental factors. 3.3 Require an annual work plan that identifies the

Organization	Yes or No	Question 2 Comment
		applicable lines to be maintained and associated work to be performed during the year. It shall be flexible to adjust to changing conditions and to findings from Vegetation Inspections. Adjustments to the plan within the year are permissible. The plan shall take into consideration permitting and scheduling requirements from landowners or regulatory authorities. It shall support the objectives of the transmission vegetation management program and utilize the methodologies outlined in the transmission vegetation management program. 3.4 Require a process or procedure for response to imminent threats[3] of a vegetation-related Sustained Outage. The process or procedure shall specify actions which shall include immediate communication of the threat to the Transmission Operator or proper operating authority. The process or procedure shall specify what conditions warrant a response.3.5 Specify an interim corrective action process for use when the Transmission Owner is constrained from performing vegetation maintenance as planned. 3.6 Specify the maintenance approach used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that Table 1 clearances in Attachment 1 are never violated. The maintenance approach shall consider the sag and sway of the conductor throughout its operating range under rated conditions.[1] ANSI A300, Tree Care Operations - Tree, Shrub, and Other Woody Plant Maintenance - Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.[2] Local factors include treatment cycle, extent and type of treatment, and their relationship to the normal growth rate.[3] The term “imminent threat” refers to a vegetation condition which is placing the transmission line at a significant risk of a Sustained Outage. Refer to Technical Reference for examples of imminent threat procedures and conditions for implementation.
Response:		
Consumers Energy	No	Consumers Energy strongly disagrees with the MVCD as presented in this version of the standard. These distances do not provide an adequate safeguard to prevent outages since the conductor position relative to the vegetation is sensitive to electric load and wind at any particular moment while vegetation height is not. Measurements M1 and M2 require real-time observation of a violation of MVCD to be reportable. As presented, vegetation growing beneath the conductor with a clearance of MVCD + 1 foot is not reportable. However, this same conductor may sag due to load increase or move due to wind displacement within hours of the real-time observation. If great enough, the sag or displacement may move the conductor in contact with the vegetation resulting in an outage just hours after being deemed compliant.At a minimum the MVCD should be designed to provide the Gallet clearance distance at maximum sag or wind displacement (whichever is greater) at all times. No matter when the line is cleared of vegetation or inspected for vegetative conditions, if the enhanced MVCD is being met an outage cannot occur until further vegetative growth occurs. Furthermore, for line clearing operations, tree crews do not and cannot determine in the field the maximum potential sag or wind displacement to know how much vegetation to clear. They require much clearer instructions with a set amount of clearing distance to obtain at the time of work. This distance must

Organization	Yes or No	Question 2 Comment
		account for maximum sag, wind displacement and the Gallet distance at a minimum.
Response:		
Cleco	No	Encroachment into the MCVD should require the owner to take immediate corrective action to mitigate the threat. Such an encroachment should not be reportable as a violation. Owners may be hesitant to communicate possible vegetation threat conditions to the TOP or proper authority if they believe it will be reported as a violation. We recommend the SDT consider modifying the measure for R1 and R2 to be applicable only in the interruption of the transmission facility.
Response:		
GCPD	No	Grant believes that R1 and R2 should be the entire standard and the rest of the requirements should be in guidelines and supplementary materials to assist in meeting the two results based requirements. We understand that some risk-based and competency based requirements are necessary for some standards. Not this one. No grow-in caused outages is the objective. Requiring a specific plan does not show competency, it just shows you have a plan. Feels very much like the existing standards. "Show us your Documentation".
Response:		
Northeast Power Coordinating Council	No	R3 specifies "...considering all possible locations the conductor may occupy assuming operation within Rating and Rated Electrical Operating Conditions." Although both "Rating" and "Rated Electrical Operating Conditions" appear in the NERC Glossary, inspection of these definitions shows that they are very vague, and "Rated Electrical Operating Conditions" uses the word "reasonably", a term FERC has previously indicated as being unacceptable. From a practical standpoint this seems to allow too much latitude to an entity to do the least amount of trimming and not consider the extra sag and swing caused by some of the more extreme operating conditions that "may" occur, such as loading to an STE or DAL limit during a higher velocity wind than normal, coupled with a higher ambient temperature. An entity could potentially claim that vegetation was trimmed to normal load levels, normal facility loading sag, and minimum velocity wind speed swings, and be within the tolerance of the standard as we interpret it. The Drafting Team should clarify what the expectation is with regard to line loading, sag, and swing due to wind speed and the types of operating conditions it deems to be justified to create a more exact requirement.
Response:		

Organization	Yes or No	Question 2 Comment
Nebraska Public Power District	No	same concern as item 1.
Response:		
Central Maine Power, Iberdrola USA	No	The TVMP must include clearances bewteen trees and conductors at time of vegetation management work.Suggest that the TVMP require the use of qualified personnel to manage this program.
Response:		
Arizona Public Service Company	No	This standard lacks accountability and transparency. This is a reliability standard and the industry is to prevent outages within the active ROW. It doesn't matter if the vegetation grows-in, blows-in or falls into the conductor these are all outages. One is no less of an outage than the other one. They should be treated equally and the utility should be held accountable for lack of maintaining the transmission system.
Response:		
FirstEnergy	No	We agree that the previous R1 was too prescriptive and are in favor of the new Requirement R3. However, we do not agree with all the wording of R3 as well as the Rationale box for R3. 1. Requirement R3 - The phrase "considering all possible locations the conductor may occupy assuming operation within Rating and Rated Electrical Operating Conditions" is confusing. We like the wording from the previous (Draft 2) of FAC-003-2 and suggest the following rewording of this phrase: "considering all possible locations the conductor may occupy throughout its operating range under all rated conditions."2. Rationale box for Req. R3 - We suggest removing the first sentence in the Rationale box for R3. The need to provide a basis on the intent and competency of the TO in maintaining vegetation is not explicitly stated in the requirement. Also, we are not sure what is meant by "competency". If it is referring to minimum required competencies for personnel performing vegetation management, that is outside the scope of this standard.
Response:		
Ameren	Yes	
Bonneville Power Administration	Yes	
City of Tallahassee (TAL)	Yes	

Organization	Yes or No	Question 2 Comment
Consolidated Edison Company of New York, Inc.	Yes	
Duke Energy	Yes	
Entergy Services	Yes	
Exelon	Yes	
FRCC Manager of Operations	Yes	
Ga Transmission Corp	Yes	
Manitoba Hydro	Yes	
North Carolina EMC	Yes	
Omaha Public Power District	Yes	
Orange and Rockland Utilities, Inc.	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	
Tennessee Valley Authority	Yes	
TO/TOP	Yes	
Tucson Electric Power Co.	Yes	

Organization	Yes or No	Question 2 Comment
Utility Risk Management Corporation	Yes	
Xcel Energy	Yes	
MRO's NERC Standards Review Subcommittee	Yes	1. NSRS agrees with the revisions to R3. With regard to operations within Ratings and Rated Conditions, are operations after a contingency considered to be within Ratings and Rated Conditions?2. Could wording be added to R3 to specify rated conditions include National Electric Safety Code conditions or assumptions?
Response:		
Florida Municipal Power Agency (FMPA) and Some Members	Yes	Although FMPA agrees with the intent of the Measures, FMPA is concerned that the measures M1 and M2 may not meet the purpose of the measures as stated in the latest draft version of the Standard Processes Manual, which states that that a Measure "(p)rovides identification of the evidence or types of evidence needed to demonstrate compliance with the associated requirement." Instead, M1 and M2 provide examples of evidence that would be used to determine non-compliance, not used to determine compliance.
Response:		
American Electric Power (AEP)	Yes	American Electric Power agrees with this change.
Response:		
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	BGE agrees with the R3 text in the latest draft of FAC-003-2.
Response:		
Dominion	Yes	Dominion agrees and finds this approach superior to existing which sometimes appears to be more administratively focused.
Response:		
JEA	Yes	Given the basic performance required in R1 and R2 of this version, I agree that specifics about what is

Organization	Yes or No	Question 2 Comment
		included in the plan are not needed. Each entity should be encouraged to write their plan so that the occasional human errors and failures that are inevitable still lead to compliance with the performance aspects of this standard. The team should be sure that the measures do not require unfailing perfect execution of this procedure so that entities are encouraged to minimize this document.
Response:		
ITC Holding	Yes	ITC feels that this draft is an improvement by clarifying the action expected by this requirement (“competency-based” program specific methodology documentation) and separating other implementing (“risk based”) actions from FAC-003-1 as new requirements within this draft version. ITC also agrees with results-based reliability, a standard principle that is driven by relevant reliability requirements and measureable results rather than prescriptive requirements driven by documentation.The term “bulk power system” should not be used in the comment form or any other documentation associated with FAC-003-2.
Response:		
Independent Electricity System Operator	Yes	Old Requirement R1 has been distilled down to its essential elements with the removal of the detailed sub-requirements that were previously included. This places the onus of developing an effective transmission vegetation management program (TVMP) on the asset owners where it ought to be, since they have the requisite expertise. Guidance is however provided in the Technical Reference document to assist Transmission Owners in developing a TVMP that in their view works for them, and achieves the overall objective of preventing those vegetation related outages that could lead to Cascading. By specifying the “what” appropriately and leaving the “how” to the entity, the entity is now in the best position to determine the most effective deployment of its resources for meeting the goals of the standard.
Response:		
CenterPoint Energy	Yes	R3 focuses on its intended impact on Sustained Outages without being overly prescriptive.
Response:		
Southern California Edison Company	Yes	SCE prefers the results-based approach to crafting reliability standards because it provides utilities with the necessary flexibility to develop internal criteria based on widely accepted best practices and industry innovations.
Response:		

Organization	Yes or No	Question 2 Comment
Western Area Power Administrtaion	Yes	The old Draft 2 version of R1 was developed to give the regulatory entities substantial and tangible information from which to judge the adequacy of a TO's overall approach to program management. The old Draft 2 version of R1 was purposely crafted in this detailed manner as an alternative to attempting to manage the problematic CCZ concepts contained in Draft 1. Industry strongly rejected the CCZ management concepts contained in Draft 1 in the first comment period. It appears that the current Draft 3 version of R3 has lost some of the content needed to fully substitute for the management of Draft 1 CCZ concepts. The addition of an implementation requirement intended to measure the full execution and success of the overall management approach identified by a TO in response to the new R3 may help to address this shortcoming. As currently worded, the requirement to simply execute a flexible annual work under the new R7 in Draft 3 does appear extensive enough to fulfill this need.
Response:		
Oncor Electric Delivery	Yes	The RBS defense-in-depth strategy for this Standard does provide an adequate level of reliability. The Standards purpose statement refers to the electric Transmission system and corresponding applicable lines not the BPS or BES as currently defined in the NERC glossary or being proposed (NOPR) RM09-18-000. Removing prescriptive requirements allows utilities flexibility to document their program and perform their vegetation management to achieve the goal of no outages that lead to cascading.
Response:		
IRC Standards Review Committee	Yes	The SRC agrees with the intent of R3, but questions the need for inspection postponements to be limited to natural "disasters". A well-planned inspection may be delayed by a common lighting storm. While there is a need to conduct the inspections and those inspections could be done anytime within the TO's own plans - the SDT may want to modify the exception to be natural disasters or other conditions that are reported within 5 business days and agreed to as an excused condition by the Regional Reliability Organization.
Response:		
Southen Company	Yes	The term “bulk power system” should not be used in the comment form or any other documentation associated with FAC-003-2.
Response:		
Progress Energy Carolinas	Yes	This separates implementing actions such as inspections, annual plans and imminent threat procedures from TVMP methodology (which proves competency of the program).This draft is an improvement by clarifying the

Organization	Yes or No	Question 2 Comment
		action expected by this requirement ("competency-based" program specific methodology documentation) and separating other implementing ("risk based") actions from FAC-003-1 as new requirements within this draft version.
Response:		
SERC OC Standards Review Group	Yes	This separates implementing actions such as vegetation inspections, performing annual work plans and responding to imminent threats from the required documentation of the TVMP methodology (which proves competency of the program).This draft is an improvement by clarifying the action expected by this requirement (program specific methodology documentation requirement) and separating other implementing actions from FAC-003-1 as new requirements in this draft version.
SERC Vegetation Management Sub-committee	Yes	This separates implementing actions such as vegetation inspections, performing annual work plans and responding to imminent threats from the required documentation of the TVMP methodology (which proves competency of the program).This draft is an improvement by clarifying the action expected by this requirement (program specific methodology documentation requirement) and separating other implementing actions from FAC-003-1 as new requirements in this draft version.
Response:		
Western Area Power Administration - Upper Great Plains Region	Yes	WAPA - UGPR agrees with a reliability based standard. In the plains states, we have fewer trees than many utilities, so having prescriptive requirements that assume we have lines running through forested areas seems to mandate an excessive amount of detail. We prefer to keep our program very simple -- perform periodic inspections to identify vegetation problems and then direct applicable resources in to take care of the problem. Our hope is that a results-based reliability standard will provide some flexibility for those utilities with smaller scale vegetation encroachments.
Response:		
Ad Hoc Group subteam formed to review draft standard	Yes	While the new R3 is less prescriptive than the old R1, it appears to stray from criteria #4 for developing results-based standards, as described in this comment form. It appears to require only the development of a document. We understand that in some cases this cannot be avoided. We believe that this is one of those cases where the reliability objective of building competency in considering all possible locations the conductor may occupy and assuming operation within Rating and Rated Electrical Operating Conditions over-rides our reluctance in requiring a registered entity to produce a document rather than a result. We suggest that in a future revision to standard that this can be combined with R7 to create a comprehensive requirement that the

Organization	Yes or No	Question 2 Comment
		entity have a vegetation management program that demonstrates it is able to perform those actions necessary to keep vegetation out of the MVCD.
Response:		
KCPL	No	The measures for R1 and R2 are zero tolerance for encroachments into the MVCD that did not result in a “contact” with the transmission facility. Considering the substantial number of miles of transmission involved, the complexities in anticipation of vegetation growth with numerous growth variables, vegetation management limitations imposed by other regulations or requirements, and unexpected transmission events that require substantial efforts regarding physical restoration, it is not reasonable or practical for the measures here to include encroachments that do not result in an interruption of transmission service. Recommend the SDT consider modifying the measures for R1 and R2 to be applicable only in the interruption of a transmission facility.
Response:		

3. Do you agree with the overall layout of the proposed template? If not, please suggest an alternative layout.

Summary Consideration:

Organization	Yes or No	Question 3 Comment
TO/TOP		
Westchester County Board of Legislators		
American Transmission Company	No	a.) ATC believes that the “Guideline and Technical Basis” section does not belong within the NERC Standard. ATC feels there are parts of this section that appear to obligate the TO with additional mandatory requirements. (please refer to additional details in Question #8 below) b.) ATC believes the “Measures” section immediately following the Requirement is helpful and placement is appropriate, however, the introductory statement in R1 and R2 is poorly worded. For example, M1 currently states: “ Evidence of violation of Requirement R1 is limited to:” ATC feels this is a negative approach and recommends that it be stated in a positive manner such as”” Evidence of compliance to R1 would be to: o Not have any vegetation-related Sustained Outages due to a grow-in.” c.) ATC would like to clarify whether the “Rational” boxes remain within the final standard. It seems appropriate to have this information but that it would be better to have this information appear in the “Guideline and Technical Basis” section.
Response:		
GCPD	No	Don't need all the extra requirements beyond R2.
Response:		
Florida Municipal Power Agency (FMPA) and Some Members	No	FMPA appreciates the improvements and has additional suggestions. Please see responses to the remainder of the questions, and below, for suggestions:The evidence retention should be grouped with the Measures for ease of creating a records retention schedule for the standards and requirements.Do we really need a “Compliance Monitoring and Enforcement Processes” section of the standards? Are there any standards that don’t have all of these activities?
Response:		

Organization	Yes or No	Question 3 Comment
City of Tallahassee (TAL)	No	I would delete the Rationale in favor of keeping the Guideline and Technical Basis. The Guideline appears to be more in-depth than the Rationale. This makes the Rationale unnecessary.
Response:		
Northeast Power Coordinating Council	No	NPCC participating members want to thank the drafting team for the hard work devoted to developing this standard, and recognize the difficult issues of producing the first “results based” proof of concept standard and offer the following, not as criticism, but as helpful suggestions for their consideration based on a cross section of stakeholder reactions to the draft. 1) Measures are compliance related elements and should not appear immediately after the requirements. The older template had the compliance elements grouped together in a separate section, and we suggest this continues. In the past there have been instances of RSAW (Reliability Standards Audit Worksheets) not clearly matching the standard’s requirements or measures. We suggest that this initiative with a results based requirement consistently involve the development of the associated RSAWs to ensure coordination, and also that the requirement results in a performance based, competency, or risk based reliability criterion. 2) Effective dates have become a complex issue. We suggest that rather than having an effective date table in the standard, this type of information be restricted to the implementation plan and ultimately reside in a NERC relational database which is currently under discussion/development. NPCC participating members suggest that the “Effective Dates” section be replaced with “NERC BOT Adopted Date”. Due to their complexities, FERC and Provincial approvals are something best left to implementation plans and databases. 3) “Rationale” boxes appearing in the Requirements section are problematic. If a “Rationale” box is required to explain part of the requirement then the requirement needs to be revised. For example, in R7 the requirement states that a TO shall execute a flexible annual vegetation management plan. Flexible in this context could have many different interpretations, yet in the “Rationale” box the use of the word flexible is clearly delineated to mean work may be deferred if not an imminent threat. In general we believe these boxes add little value, and if the requirement can’t be understood without the “Rationale” then the requirement needs to be worded appropriately. Suggest these types of explanatory statements go into guidance documents, or supporting technical documents, and do not appear in the “Requirements” sections. 4) Also, there seems to be some confusion regarding the Administrative Procedure section. There seems to be requirements embedded within it, e.g. “The Transmission Owner will submit a quarterly report to its Regional Entity, or the Regional Entity’s designee, identifying all Sustained Outages of transmission lines determined by the Transmission Owner....” Is this an enforceable aspect of the standard? If so, are there any other documents such as the NERC Rules of Procedure “ROP” or compliance related documents such as the CMEP that have to be changed? NPCC participating members recognize that this is a results based standard. Administrative requirements should be removed from the standards, and dealt with elsewhere (such as the ROP). 5) The Guideline and Technical Basis section contains valuable information, but this adds to the volume of the document. The Drafting Team

Organization	Yes or No	Question 3 Comment
		should consider moving this to a separate document. In viewing the standards as a whole, the FAC-003 standard is relatively straightforward when compared to the developing of other standards such as the TPL standard. A similar approach, if applied to the TPL would result in a standard with potentially hundreds of pages. If the type of work appearing in this section is envisioned for other more complex standards such as TPL, the DT should consider separating out this section as a single supporting document. 6) Do FERC and the Provincial governmental authorities approve just the requirements in the Standard, or the whole package?
Response:		
FRCC Manager of Operations	No	See responses to #8, 10, 11 and 13.
Response:		
IRC Standards Review Committee	No	The proposal to move the time horizon and the VRF to a separate independent section is not useful. Take for example R1 and R2 of the proposed standard. A careful read of the two requirements and measurements would indicate that there is no difference between them and that it would be better to have one requirement for all conductors. It is not until the reader gets to the compliance section does the VRF difference show up. There is no savings to removing the previous format's parenthetical inclusion of time horizon and VRF at the end of the requirement. The Independent Section can contain all of the proposed information but don't remove it from the requirement. The format of the standard would not be an issue if NERC would develop a standards database. Then, the database could be queried in any format the user desires.
Response:		
ERCOT ISO	No	The Standard itself is several pages into the document. The VRFs/VSLs should be in the Requirements/Measures Section. The Background, Rationale, Administrative Procedures are additional information and should be located in an Appendix so it doesn't clutter the Standard.
Response:		
CenterPoint Energy	No	We suggest combining and moving the Rationale, Background, Guideline and Technical Basis, and Technical Reference to a consolidated appendix because there is much duplication in the wording within each of these sections, and independently they may be misinterpreted as being an integral part of the Requirements and Measurements which they are not. The Requirements and Measurements should stand clearly on their own. The appendix should contain examples of how to meet the requirements under various circumstances. The appendix should be supplementary and optional to the Standard.It is also not clear if the Administrative

Organization	Yes or No	Question 3 Comment
		Procedure is a mandatory activity. It would be helpful if the intent of this section was stated within the Standard.
Response:		
NERC Staff (12 staff members)	No	We suggest using two colors for explanatory information - yellow for information that is temporary - such as the information explaining the difference between the approved and proposed definitions of “Vegetation Inspection” - and using blue for all boxes that are intended to remain in the approved standard.We feel that the Standards Committee Process Subcommittee should pursue adding a statement from NERC’s legal department indicating which parts of the standard are enforceable. In the meantime, we suggest using the standard template in order to clearly define the enforceable parts of the standard. The section identified as “Guideline and Technical Basis” is not really a guideline (typically a proposed process for completing work) and is not really a “technical basis” (typically a summary of research or engineering judgment, etc. used to explain the reasoning for something). The information in this section is explaining how the drafting team expects compliance with the requirements to be measured. We suggest revising the heading to “Application Guidelines.” This is the term that was originally proposed by the Results-based team and is the heading identified in the proposed Standard Processes Manual.
Response:		
Ad Hoc Group subteam formed to review draft standard	Yes	
Arizona Public Service Company	Yes	
Bonneville Power Administration	Yes	
Central Maine Power, Iberdrola USA	Yes	
Cleco	Yes	
Consumers Energy	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 3 Comment
Entergy Services	Yes	
Exelon	Yes	
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
Nebraska Public Power District	Yes	
North Carolina EMC	Yes	
Omaha Public Power District	Yes	
Oncor Electric Delivery	Yes	
Orange and Rockland Utilities, Inc.	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	
Southen Company	Yes	
Southern California Edison Company	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	

Organization	Yes or No	Question 3 Comment
Xcel Energy	Yes	
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	BGE is supportive of the proposed template.
Response:		
JEA	Yes	Coupling the measures and rationale with each requirement make the standard easier to follow and to implement.
Response:		
Dominion	Yes	Dominion agrees, but suggests that reference(s) to figure(s) and table(s) contain links that can take reader to that section of the document. This is superior to having to scroll through document. If the reference(s) is external to this standard document, links may be harder to manage but should at least reference a common webpage(s) used by NERC for the posting of such documents.
Response:		
ITC Holding	Yes	ITC feels that the overall layout of the standard (a) improves readability, (b) clarifies expectations, (c) reduces confusion associated with referencing between pages, and (4) allows for background information and the SDT rationale to accompany the standards but we would suggest locating Guideline and Technical Basis after Requirements and Measures for better reference accessibility.
Response:		
MRO's NERC Standards Review Subcommittee	Yes	N/A
Tampa Electric Company	Yes	None
Western Area Power Administration - Upper Great Plains Region	Yes	None

Organization	Yes or No	Question 3 Comment
FirstEnergy	Yes	Overall, we like the layout of the standard, especially the Effective Date table in the front of the standard, the combination of Requirements and Measures, and the grouping of the VRF, Time Horizons, and VSL into one table. However, we would like to see a clearer delineation between the mandatory requirements and the guidance and rationale information. The standard should explicitly be clear as to what is mandatory and what is not, which may even require moving the "Rationale" text boxes out of the Requirements and Measures section. FE believes the information presented in the Rationale text boxes can be effectively covered in the "Guidelines and Technical Basis".
Response:		
Western Area Power Administrtaion	Yes	The format could be enhanced by moving the Guidelines and Technical Basis section forward to be included with the corresponding Requirement, Measure, and Rationale. This would be helpful because it is awkward flipping back and forth between these two sections when trying to fully understand a requirement.
Response:		
Pepco Holdings, Inc. - Affiliates	Yes	The general layout is quite effective. Still, it would be good to keep the VRFs and time horizons within the text of the requirement.
Response:		
Ga Transmission Corp	Yes	The layout is adequate but many things are needing further explanation such as the MVCD.
Response:		
Progress Energy Carolinas	Yes	The overall layout improves readability, clarifies expectations, reduces confusion associated with referencing between pages, and allows for background information and SDT rationale to accompany the standards (reducing the need for interpretation).
Response:		
SERC OC Standards Review Group	Yes	The overall layout improves readability, clarifies expectations, reduces confusing references between pages, and allows for background and rationale to accompany standards.
SERC Vegetation Management	Yes	The overall layout improves readability, clarifies expectations, reduces confusing references between pages,

Organization	Yes or No	Question 3 Comment
Sub-committee		and allows for background and rationale to accompany standards.
Response:		
East Kentucky Power Cooperative, Inc.	Yes	The overall layout is greatly improved. This draft is easier to read and understand and clarifies the expected actions required in the standard.
Response:		
American Electric Power (AEP)	Yes	The overall template layout is acceptable
Response:		
Tennessee Valley Authority	Yes	This aids the understanding of the standard.
Response:		
Ameren	Yes	This draft is much more user friendly and easier to follow; appreciate the follow up information.
Response:		
Consolidated Edison Company of New York, Inc.	Yes	We do believe the overall layout is effective but the SDT should consider putting the Background Section before the Applicability Section in the Introduction and also try to reduce any redundant verbiage in the Background Section and the Guideline and Technical Basis Section. A twenty-one page Standard is too lengthy and the supporting Technical Reference document properly addresses many of the issues mentioned in the Guideline and Technical Basis Section.
Response:		
KCPL	Yes	

4. Do you agree with grouping the standard development timeline (previously called roadmap) with the revision history, and the effective date(s) and putting this administrative information up front before the Introduction Section? Please explain.

Summary Consideration:

Organization	Yes or No	Question 4 Comment
FRCC Manager of Operations		
TO/TOP		
Westchester County Board of Legislators		
IRC Standards Review Committee	No	For this standard one must read through 7 pages before getting to the reason for the posting. The administrative information should be relegated to the end of the posting not the beginning.Under exceptions in the Effective Dates section of the standard, IROLs are referenced as only being created by the Planning Coordinator. Because Reliability Coordinators must also establish IROLs per FAC-011 and FAC-014, we suggest that reference to the Planning Coordinator should be redacted and IROLs should be discussed regardless of whether the Planning Coordinator or Reliability Coordinator creates them.
Response:		
Consolidated Edison Company of New York, Inc.	No	The only issue we have with the administrative information being before the Introduction Section is with the Definition of Terms Used in the Standard Section. We feel this should be part of the Introduction and not a stand alone section.
Orange and Rockland Utilities, Inc.	No	The only issue we have with the administrative information being before the Introduction Section is with the Definition of Terms Used in the Standard Section. We feel this should be part of the Introduction and not a stand alone section.
Response:		
ERCOT ISO	No	This information should be located at the end so that it doesn't distract from the main purpose of the Standard. It is cumbersome to read through several pages before getting to the actual language of the

Organization	Yes or No	Question 4 Comment
		Standard.
Response:		
Ad Hoc Group subteam formed to review draft standard	Yes	
American Transmission Company	Yes	
Arizona Public Service Company	Yes	
Bonneville Power Administration	Yes	
Central Maine Power, Iberdrola USA	Yes	
City of Tallahassee (TAL)	Yes	
Cleco	Yes	
Consumers Energy	Yes	
Duke Energy	Yes	
Exelon	Yes	
GCPD	Yes	
JEA	Yes	
Manitoba Hydro	Yes	
Nebraska Public Power District	Yes	

Organization	Yes or No	Question 4 Comment
NERC Staff (12 staff members)	Yes	
North Carolina EMC	Yes	
Omaha Public Power District	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	
Southen Company	Yes	
Tennessee Valley Authority	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	
Western Area Power Administrtaion	Yes	
Ameren	Yes	Appreciate the ability to reference up front.
Response:		
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	BGE agrees with the proposed grouping and placement of these items.

Organization	Yes or No	Question 4 Comment
Response:		
Dominion	Yes	Dominion agrees that the new format is superior to the old. However, we suggest a table of contents be added to include at a minimum, sections for (1) Definitions of Terms Used in Standard (2) Effective dates, (3) Introduction, (4) requirements and measures (5) Compliance (6) Time Horizons, VRF and VSLs (7) Administrative (8+) guidelines, technical basis, tables or figures referenced in standard.
Response:		
Entergy Services	Yes	Easy to follow.
Response:		
Ga Transmission Corp	Yes	I do not see a problem with this change.
Response:		
Xcel Energy	Yes	It is acceptable to do so, however it is not clear as to how the effective date portion will be incorporated in a final version of the standard. Will there be some kind of cover page to at least indicate the standard or will it just be a small title bar at the top? (i.e. - what does page 1 of the standard look like?)
Response:		
ITC Holding	Yes	ITC agrees with locating the revision history and administrative information before the introduction. This alignment improves clarity and readability by providing a single location for this information.
Response:		
Florida Municipal Power Agency (FMPA) and Some Members	Yes	Just a question, when the standard becomes effective, how will it be posted? FMPA assumes that this section will move to the end of the standard instead of the front when approved.
Response:		
CenterPoint Energy	Yes	No preference.

Organization	Yes or No	Question 4 Comment
Tampa Electric Company	Yes	None
Northeast Power Coordinating Council	Yes	NPCC participating members believe this is acceptable. However our previous response to question 3 above still applies regarding the Effective Date section. It should be removed from the standard, and either appear in an implementation plan, or more effectively in a NERC relational database.
Response:		
Independent Electricity System Operator	Yes	Since in this case the effective dates of all requirements are all the same, we believe the effective dates table could be significantly condensed.
Response:		
East Kentucky Power Cooperative, Inc.	Yes	The format provides for better clarification and is easier to read and comprehend.
Response:		
MRO's NERC Standards Review Subcommittee	Yes	The NSRS likes the way the standards is now formatted and finds it more user friendly.
Response:		
American Electric Power (AEP)	Yes	These changes make sense to American Electric Power.
Response:		
SERC OC Standards Review Group	Yes	This format adds clarity and improves readability.
SERC Vegetation Management Sub-committee	Yes	This format adds clarity and improves readability.
Response:		

Organization	Yes or No	Question 4 Comment
Progress Energy Carolinas	Yes	This grouping improves clarity and readability by providing a single location for this information.
Response:		
Western Area Power Administration - Upper Great Plains Region	Yes	WAPA - UGPR is neutral on location of these items.
Response:		
Southern California Edison Company	Yes	We agree that grouping the administrative information up front is logical and makes for a cleaner presentation.
Response:		
FirstEnergy	Yes	We agree with having a detailed table showing the effective dates of each requirement. However, we would like to see NERC go back into the table and specify the dates of NERC and FERC effective dates once they are known. Having the statement "1st day of the 1st quarter one year after applicable regulatory approval" in the standard does not help the user of the standard when they are working towards compliance, and requires them to go elsewhere to find when the approvals took place. All this information should be in the standard when available and NERC staff should be afforded the latitude to do so even without needing to use its Errata process. Placing the dates directly within the standard is more convenient for the end user.
Response:		
KCPL	Yes	

5. Do you agree with grouping the Requirements and Measures together, in one Section now called Requirements and Measures? Please explain.

Summary Consideration:

Organization	Yes or No	Question 5 Comment
Westchester County Board of Legislators		
Xcel Energy		We are indifferent as to the placement of the Measures, however it does appear to create awkward shaped paragraphs when Requirements and Measures are place around Rationale boxes.
Response:		
Northeast Power Coordinating Council	No	As commented earlier in question 3, this is a compliance related issue and should be in the Compliance section. NPCC participating members believe clear concise requirements should be the focus, and inserting measures immediately after the requirements adds little value. In addition, RE compliance staffs who use the metrics find no value to moving it as well. This format would ease working with the document as a working draft, but should not be in an adopted document. Consider moving Measures back to the compliance section, and add a reference to a Measure's wording stating which requirement the measure refers to. Only adding a statement when the Requirement and Measure numbering don't line up could be considered.
Response:		
Bonneville Power Administration	Yes	
Cleco	Yes	
Duke Energy	Yes	
IRC Standards Review Committee	Yes	
Manitoba Hydro	Yes	

Organization	Yes or No	Question 5 Comment
Nebraska Public Power District	Yes	
NERC Staff (12 staff members)	Yes	
North Carolina EMC	Yes	
Omaha Public Power District	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	
Southen Company	Yes	
Southern California Edison Company	Yes	
TO/TOP	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	
Western Area Power Administrtaion	Yes	
Central Maine Power, Iberdrola USA	Yes	Adds clarity between requirements and measures .

Organization	Yes or No	Question 5 Comment
Response:		
Arizona Public Service Company	Yes	APS doesn’t agree with all of the requirements.
Response:		
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	BGE agrees it makes sense to group these two sections together.
Response:		
JEA	Yes	Coupling the measures and rationale with each requirement make the standard easier to follow and to implement.
Response:		
Dominion	Yes	Dominion finds this format improved over the existing as reader can more easily correlate the requirement (process/procedures) to the measure (evidence).
Response:		
Exelon	Yes	Exelon agrees this is a good practice that will help ensure Requirements and Measures are aligned
Response:		
Florida Municipal Power Agency (FMPA) and Some Members	Yes	FMPA agrees that grouping the Requirements and Measures together in one section is a great idea; however, to realize even more benefit, we now have the opportunity to eliminate redundant wording, e.g., M3 can be shortened to: “A documented transmission vegetation management program” and eliminate the rest of the words that are redundant with R3.
Response:		
Entergy Services	Yes	Great addition and improvement!! Much clearer and easier to follow.

Organization	Yes or No	Question 5 Comment
Response:		
City of Tallahassee (TAL)	Yes	However, if you keep the Rationale text boxes, keep the Measures in the same column as the requirement. This will result in a more consistent “look and feel” to all the requirements (M3 for R3 is the example).
Response:		
FRCC Manager of Operations	Yes	In addition the DT could also eliminate redundant wording in the standard requirement, e.g., M3 can be shortened to: “A documented transmission vegetation management program” and eliminate the rest of the words that are redundant with R3 or use words in the measure that refer back "to the requirement above".
Response:		
ERCOT ISO	Yes	Including a specific measure with each requirement adds clarity; however, it isn’t clear whether each measure is exclusive to the requirement that it follows. Is it possible that some requirements will have multiple measures that are not listed immediately following the requirement?
Response:		
ITC Holding	Yes	ITC agrees with Requirements and Measures grouped together
Response:		
GCPD	Yes	Makes the standard template much easier to read and use.
Response:		
Consumers Energy	Yes	Much easier to follow in this format.
Response:		
Ameren	Yes	Much more user friendly to be able to see the requirement and the measurement together for clarification.
Response:		

Organization	Yes or No	Question 5 Comment
CenterPoint Energy	Yes	No preference.
MRO's NERC Standards Review Subcommittee	Yes	NSRS prefers to have the requirements, measures, VRFs, VSLs and Time Horizons together instead of referencing to another page or part of the standard.
Response:		
American Transmission Company	Yes	See ATC's comment on "Measures" in Question #3 above.
Response:		
Tennessee Valley Authority	Yes	This aides in understanding of the standard. Grouping the VSL and VRF for each requirement along with the measurement could be beneficial too.
Response:		
Ga Transmission Corp	Yes	This also is OK no problem with the layout.
Response:		
Progress Energy Carolinas	Yes	This change also improves readability and improves understanding of the requirement.
Response:		
SERC OC Standards Review Group	Yes	This format adds clarity and improves readability.
SERC Vegetation Management Sub-committee	Yes	This format adds clarity and improves readability.
Response:		
East Kentucky Power	Yes	This format provides for better readability and clarification.

Organization	Yes or No	Question 5 Comment
Cooperative, Inc.		
Response:		
Tampa Electric Company	Yes	This improves the clarity and understanding to the requirements.
Response:		
Independent Electricity System Operator	Yes	This is useful to avoid having to move back and forth between separate sections to find out what is needed to show that a requirement is met. We do not have a strong preference for this re-grouping however.
Response:		
Western Area Power Administration - Upper Great Plains Region	Yes	WAPA - UGPR believes this makes it easier to identify the requirement and what we need to provide to demonstrate with are in compliance with the requirement.
Response:		
FirstEnergy	Yes	We agree that grouping the Requirements and Measures together is convenient when utilizing the document for compliance.
Response:		
Consolidated Edison Company of New York, Inc.	Yes	We agree with grouping the Requirements and Measures together since it does add another level of clarifying description for our field forces who are ensuring compliance during vegetation management activities. The Measures for R1 and R2 describe evidence of violation while the Measures for the remaining Requirements R3 - R7 describe evidence of compliance. All Measures should be written consistently as either evidence of compliance or evidence of violation.
Response:		
Orange and Rockland Utilities, Inc.	Yes	We agree with grouping the Requirements and Measures together since it does add another level of clarifying description for our field forces who are ensuring compliance during vegetation management activities. The Measures for R1 and R2 describe evidence of violation while the Measures for the remaining Requirements R3 - R7 describe evidence of compliance. All Measures should be written consistently as either evidence of

Organization	Yes or No	Question 5 Comment
		compliance or evidence of violation.
Response:		
Ad Hoc Group subteam formed to review draft standard	Yes	We agree with the understanding that the specific requirements of the standard are the enforceable elements of the standard. The rationale and measures add clarity to support a results-based requirement.
Response:		
American Electric Power (AEP)	Yes	Yes, this is a more readable format.
Response:		
KCPL	Yes	

6. Do you agree with grouping VRFs, Time Horizons and VSLs together, and putting them in a table separate from the Requirements and Measures Section? Please explain.

Summary Consideration:

Organization	Yes or No	Question 6 Comment
Westchester County Board of Legislators		
Pepco Holdings, Inc. - Affiliates	No	Agree that the grouping of the subject material is appropriate, but it is not necessary to also remove the VRFs and time horizons from the requirement.
Response:		
JEA	No	I would prefer to have the VRF's and time horizons together with the requirements and measures section. The VSL's separate is appropriate as that is not information needed while complying, but only after a failure.
Response:		
Manitoba Hydro	No	If the VRF's Time Horizons and VSLs were listed in with each requirement and measure section, it would eliminate the need for cross referencing 2 sources of information.
Response:		
Oncor Electric Delivery	No	It would be nice to see the associated VRF's and Time Horizon with the requirements. No text, but referenced.
Response:		
ERCOT ISO	No	The associated VRFs/Time Horizons/VSLs should be identified alongside each Requirement so that all relevant criteria for a given Requirement are organized together.
Response:		

Organization	Yes or No	Question 6 Comment
IRC Standards Review Committee	No	While we agree that the grouping of the subject material is appropriate, it is not necessary to also remove the VRFs and time horizons from the requirement.
Response:		
Duke Energy	No	While we like grouping VRFs, Time Horizons and VSLs together in a table, we would also like to see each VRF and Time Horizon listed with its requirement. It's a small amount of information that we think adds value in both places.
Response:		
Ad Hoc Group subteam formed to review draft standard	Yes	
Ameren	Yes	
American Transmission Company	Yes	
Arizona Public Service Company	Yes	
Bonneville Power Administration	Yes	
Central Maine Power, Iberdrola USA	Yes	
Cleco	Yes	
Consolidated Edison Company of New York, Inc.	Yes	
Consumers Energy	Yes	
Dominion	Yes	

Organization	Yes or No	Question 6 Comment
East Kentucky Power Cooperative, Inc.	Yes	
Exelon	Yes	
FRCC Manager of Operations	Yes	
Independent Electricity System Operator	Yes	
Nebraska Public Power District	Yes	
North Carolina EMC	Yes	
Omaha Public Power District	Yes	
Orange and Rockland Utilities, Inc.	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	
Southern California Edison Company	Yes	
TO/TOP	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	

Organization	Yes or No	Question 6 Comment
Western Area Power Administrtaion	Yes	
Xcel Energy	Yes	
MRO's NERC Standards Review Subcommittee	Yes	Again it is good to have this information together in place of referencing some other page or part of the Standard.
Response:		
Tennessee Valley Authority	Yes	Also please consider parsing out a copy of each VSL/VRF with in each individual requiremnt and measure part of the standard as mentioned in question 5 above.
Response:		
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	BGE supports grouping VRFs and VSLs together in a separate table.
Response:		
Southen Company	Yes	Consider putting the appropriate line from the table with each requirement in the body of the standard in addition to the table format. This does make the standard longer and does introduce some redundancy, but it would make each requirement easier to read and interpret on a “standalone” basis.
Response:		
City of Tallahassee (TAL)	Yes	I believe this makes it easier to follow the Requirements.
Response:		
ITC Holding	Yes	ITC Agree's
Response:		

Organization	Yes or No	Question 6 Comment
Florida Municipal Power Agency (FMPA) and Some Members	Yes	Much easier to find and understand
Response:		
CenterPoint Energy	Yes	No preference.
Entergy Services	Yes	This grouping helps to clarify the manner in which the violations will be ranked.
Response:		
Progress Energy Carolinas	Yes	This grouping improves the template used by previous versions by providing a single view of the impact and risk that has been associated with each requirement. Progress Energy believes that this change would also be improved if the applicable VRF/VSL/Time Horizon table rows were also listed with each requirement (consolidating pertinent info with the requirement). Another improvement would be including the penalty matrix (or including a URL link) to facilitate Transmission Owner discussions with property owners and other governmental agencies.
Response:		
SERC OC Standards Review Group	Yes	This improves the template used by previous versions by providing a single view of the impact consideration of each requirement. An improvement would be also listing the applicable table rows with each requirement which consolidates all pertinent info with the requirement. Also, adding the penalty matrix would facilitate discussions with property owners/agencies resisting maintenance activates.
Response:		
SERC Vegetation Management Sub-committee	Yes	This improves the template used by previous versions by providing a single view of the impact consideration of each requirement. An improvement would be also listing the applicable table rows with each requirement which consolidates all pertinent info with the requirement. Also, adding the penalty matrix would facilitate discussions with property owners/agencies resisting maintenance activates.
Response:		
GCPD	Yes	This is audit stuff that does need to stay together.

Organization	Yes or No	Question 6 Comment
Response:		
Northeast Power Coordinating Council	Yes	This is consistent with FERC's determination that these are compliance elements and not part of the standard requirements. It will also assist with compliance determinations.
Response:		
Western Area Power Administration - Upper Great Plains Region	Yes	WAPA - UGPR is neutral on location of these items.
Response:		
FirstEnergy	Yes	We agree with grouping these items together. It may also be beneficial to include links directly in the table to explanations of VRFs, Time Horizons, and VSLs so that someone unfamiliar with, for instance, what a "Long-Term Planning" horizon means, they could look it up.
Response:		
NERC Staff (12 staff members)	Yes	We agree with the idea behind the grouping. However, according to the Reliability Standard Development Procedure - Version 7, although a non-binding poll is taken of the VRFs and VSLs, it appears that the Time Horizons are part of the standard that is still subject to stakeholder ballot. The SDT should explain how this will be made clear to balloters. Is there intent to modify the standards process to remove the time horizons from the portions of the standard that are subject to ballot? This issue needs to be addressed by the Standards Committee Process Subcommittee.
Response:		
Tampa Electric Company	Yes	With all of the VRFs, Time Horizons and VSLs grouped together it facilitates the overall understanding of these factors as they relate to the standard.
Response:		
Ga Transmission Corp	Yes	Yes this was a good change.

Organization	Yes or No	Question 6 Comment
Response:		
American Electric Power (AEP)	Yes	Yes; this format is more user-friendly.
Response:		
KCPL	Yes	

7. **Do you agree with the insertion of text boxes, where necessary, to help readers better understand the basis of the Definitions and Requirements? Please explain.**

Summary Consideration:

Organization	Yes or No	Question 7 Comment
Westchester County Board of Legislators		
Exelon	No	Additional clarifications should be included in appendices or reference documents. Including them with the requirements and measures will cause confusion concerning what the compliance obligation is. This will introduce uncertainty to the compliance monitoring process.
Response:		
American Transmission Company	No	Although the test boxes provide some addition help, ATC believes that these text boxes should appear in the Guideline and Technical Basis section and that whole section should appear in a companion document to the standard but not be included as part of the standard. Also, see ATC's comment on Rational in Question #3 above.ATC believes that guidance information should not be reviewed and approved by FERC and the inclusion of such information within the standard opens this language up to FERC's oversight and approval.
Response:		
Northeast Power Coordinating Council	No	As stated in question 3 above, NPCC participating members believe crisp, clear results based requirements require no further explanation. Requirements must be written so they are clearly understood. Text boxes clutter up the standard. Questions could arise if these add "pseudo" requirements to the standards, and there is any inconsistency in what is stated about requirements. NPCC strongly suggests their removal in favor of clear, measurable, and high quality results based requirements.
Response:		
City of Tallahassee (TAL)	No	I would delete the Rationale in favor of keeping the Guideline and Technical Basis. The Guideline appears to be more in-depth than the Rationale. This makes the Rationale redundant and unnecessary.

Organization	Yes or No	Question 7 Comment
Response:		
CenterPoint Energy	No	It is not clear how the information in the text boxes will be used to determine compliance with the Requirements and Measures. It appears that in the Definition of Terms Used in Standard section that the text boxes add to the definitions or are footnotes to historical information. The Definitions should stand on their own and be robust enough to ensure they are helpful in determining compliance with the Requirements and Measures. In the Requirements and Measures section, the text boxes appear to contain partial information from the Guideline and Technical Basis, and Technical Reference. In all cases the information is not helpful and provides incomplete information. The text boxes should be deleted and pertinent information to compliance should be incorporated into the Definitions, Requirements, and Measures. Any explanatory text or examples should be moved to an appendix as supplementary and optional to the Standard.
Response:		
ERCOT ISO	No	It is not clear whether the information in the text boxes is “For Information Only.” While the additional information may be helpful, it appears to add sub-requirements within the Standard. This information could be included under a “Rationale” section in an Appendix. However, if the information clouds the purpose of the Requirements or dictates how to comply, then it should be eliminated completely.
Response:		
Consumers Energy	No	Not necessary given the “Guidelines and Technical Basis”.
Response:		
Nebraska Public Power District	No	Text boxes and other supporting information are a benefit to the reader as a clarification guide, but should be placed in something other than the Standard.
Response:		
IRC Standards Review Committee	No	The concept of text boxes needs further discussion. The idea of using text boxes for clarity and explanation is valuable, but is the material in the text box mandatory? If it includes mandatory material than it is not a good idea - all mandatory requirements must be in the requirement. If the text boxes are retained to explain how a phrase is being used (e.g. to make clear what compound actions apply to what compound time frames), then yes, this approach can be invaluable.

Organization	Yes or No	Question 7 Comment
Response:		
Cleco	No	The inclusion of the text implies additional requirements. Keep quidance to a separate paper.
Response:		
Arizona Public Service Company	Yes	
Bonneville Power Administration	Yes	
Consolidated Edison Company of New York, Inc.	Yes	
Duke Energy	Yes	
FRCC Manager of Operations	Yes	
Manitoba Hydro	Yes	
Omaha Public Power District	Yes	
Oncor Electric Delivery	Yes	
Orange and Rockland Utilities, Inc.	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
Southen Company	Yes	
Tennessee Valley Authority	Yes	

Organization	Yes or No	Question 7 Comment
TO/TOP	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	
MRO's NERC Standards Review Subcommittee	Yes	1. We agree. The rationale boxes will cut down on interpretations. 2. Are the rationale boxes part of the approved standards for which registered entities will be audited. Are the rationale boxes federal law?3. Under R3, a reference to the National Electric Safety Code in the rationale box would be helpful. (The goal is to verify that utilities will not be held in violation of this standard when operating beyond the NESC conditions.)
Response:		
North Carolina EMC	Yes	Additional background in the test boxes is very helpful.
Response:		
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	BGE agrees this would help clarify the basis of the Definitions & Requirements.
Response:		
Dominion	Yes	Dominion agrees, but suggests that reference to figure(s) and table(s) contain links that can take reader to that section of the document. This is superior to having to scroll through document. If the reference(s) is external to this standard document, links may be harder to manage but should at least reference a common webpage(s) used by NERC for the posting of such documents.
Response:		
Xcel Energy	Yes	However, the boxes should be adding clarity, not "defining' terms or stipulating further requirements/criteria that must be met. See MVCD in R1 & R2 and the incorporated Table 2, and comments to #1 & #13 in this form. The standard should be able to convey the requirements without the text boxes or, if the text boxes are used, the purpose and legal import of such boxes should be clarified. Further, it should be clarifed that for

Organization	Yes or No	Question 7 Comment
		text boxes that provide examples (e.g., the boxes on page 2 in the definitions section), such boxes should clearly state that the examples are in no way limitations.
Response:		
Ga Transmission Corp	Yes	I do like the text boxes.
Response:		
ITC Holding	Yes	ITC agrees, but would like to suggest that the text boxes include additional pertinent information from the Technical Reference that would be helpful as reliability talking points to the public. Example: (R3): The following is a sample description of one combination of strategies which may be utilized by a Transmission Owner. A Transmission Owner's basic maintenance approach could be to remove all incompatible vegetation from the right of way if it has the right to do so and has no constraints
Response:		
Ameren	Yes	It's helpful to understand the SDT's logic for requirements, clarification is always appreciated.
Response:		
GCPD	Yes	May help in cutting down the volume of SAR interpretation requests.
Response:		
Central Maine Power, Iberdrola USA	Yes	R3 - this may be a good place to describe clearances at time of vegetation management work
Response:		
Florida Municipal Power Agency (FMPA) and Some Members	Yes	The clarification is important and will reduce the number of requests for interpretation if interpretation is already provided to some extent. Just a caution about how the text boxes will be used in the audit process, clarification concerning their use during compliance monitoring would be great.
Response:		

Organization	Yes or No	Question 7 Comment
NERC Staff (12 staff members)	Yes	The explanatory information posted with the proposed definitions, like the definitions, is only relevant to this standard, and some of the information is only relevant to the point where the definition becomes enforceable. What is the expectation for what will happen to this information in the future? We suggest that the text boxes associated with requirements include a reference to that requirement. (Change “Rationale” to “Rationale for R1”)
Response:		
Western Area Power Administrtaion	Yes	The format could be enhanced by moving the "Guidelines and Technical Basis" section forward to be included with the corresponding Requirement, Measure, and Rationale. Perhaps the "Guidelines and Technical Basis" could also be combined with the corresponding "Rationale" text box. This would be helpful because it is awkward flipping back and forth between these two sections when trying to fully understand a requirement.
Response:		
SERC OC Standards Review Group	Yes	This format adds clarity and improves readability.
SERC Vegetation Management Sub-committee	Yes	This format adds clarity and improves readability.
Response:		
East Kentucky Power Cooperative, Inc.	Yes	This format is simpler, easier to read, understand and implement.
Response:		
Progress Energy Carolinas	Yes	This format provides clarity and improves readability. Progress Energy believes that having SDT basis information for a requirement in the standard will reduce the need for interpretation and improve the interpretation process for a requirement, if necessary.
Response:		
Tampa Electric Company	Yes	This improves the clarity and understanding to the requirements.

Organization	Yes or No	Question 7 Comment
Response:		
American Electric Power (AEP)	Yes	This is a good change.
Response:		
JEA	Yes	This is extremely helpful in understanding the intent of the requirement
Response:		
Western Area Power Administration - Upper Great Plains Region	Yes	WAPA - UGPR believes that the expanations within the text boxes provided additional useful information.
Response:		
Entergy Services	Yes	We agree that text boxes being used for additional clarity is a benefit if used in a correct and clear manner. It needs to be specifically stated in the document that the text boxes are to be used for reference only, entities will not be required to specifically follow the language in the Rationale box, and that each utility should specify their own process for addressing each Requirement. For example....the Rationale box for R4 states that "Verified knowledge includes observations by journeyman lineman, utility arborist, or other qualified personnel.......". Our process will specify exactly who that qualified personnel is (Transmission Specialist or another qualified Entergy Employee in the Transmission Vegetation Group, for example). We will specify this in our internal processes.
Response:		
FirstEnergy	Yes	We agree that text boxes can be useful for requirements and definitions. However, the SDT may want to consider eliminating the text boxes since this information is already provided in the Guidance and Technical Basis section. Also, we have the following additional comments:General:1. With respect for the rationale text boxes for definitions, it is not clear if these boxes will be retained once the definitions are moved out of the standard and added to the NERC Glossary.2. The rationale text boxes can be beneficial for the requirements, but some of the text boxes in this current draft of FAC-003-2 seem to include prescriptiveness that is not found in the requirement. An example is in the text box for Req. R4, which implies timeliness of notification of an imminent threat with the use of the word "rapid". In the case of R4, the requirement should state that notification be carried out immediately (see our suggested rewording of R4 in Question 13). 3.

Organization	Yes or No	Question 7 Comment
		Although these text boxes are not enforceable for compliance, we are not convinced that an auditor will view this as simply guidance.Specific:1. Definition for Active Transmission Line ROW - Example 3 of Inactive ROW - Consider removing this example; situations where vegetation is left unmanaged on portions of the ROW where double-circuit structures exist with only one circuit strung with conductors poses an unnecessary increased risk for vegetation related outages. 2. Rationale box for Req. R3 - See our comments in Question 23. Rationale box for Req. R4 should be revised to state: "To ensure rapid notification of the responsible control center when an occurrence of an imminent threat condition is verified. Evidence of verified knowledge includes observations by journeyperson, lineperson, utility arborist, or other qualified personnel, or a report verified by these personnel. This notification allows the responsible control center to take the appropriate action until the threat is relieved. Appropriate actions may include a temporary reduction in the line loading or switching the line out of service."4. Rationale box for Req. R5 - (1) The last statement of this box seems incomplete. It should be revised to state: "This requirement is not intended to address situations where the transmission line is not at immediate risk and the work event can be rescheduled or re-planned using an alternate work methodology."; and (2) We suggest revising the first statement to "Legal actions filed by property owners, easement restrictions and other events...."
Response:		
Southern California Edison Company	Yes	We agree that the insertion of text boxes aids readers in understanding the basis for the Definitions and Requirements.
Response:		
Independent Electricity System Operator	Yes	We agree that the side-bars give useful contextual information that is not part of standard. This is good and avoids the reader's attention being completely redirected to a reference document when seeking clarification of the intent of a requirement. We believe however that these text boxes should be used sparingly and the content should also be brief to minimize possible distractions to the reader.It should also be made clear in the standard that these text boxes are not intended to impose additional requirements and in the event of any perceived conflict, the text of the requirement will take precedence.
Response:		
South Carolina Electric and Gas	Yes	We agree, however we would like clarification on whether entities can be held accountable for rationale portions of the standard as they are for interpretations that are added to a standard.
Response:		

Organization	Yes or No	Question 7 Comment
Ad Hoc Group subteam formed to review draft standard	Yes	We understand this question to refer to the “rationale” text boxes in this standard. Additional information such as this is useful to the entity in explaining and clarifying the understanding of the drafting team in articulating the requirement and thus supports a fuller understanding of the entity in achieving compliance with the requirement.
Response:		
KCPL	No	I like information that helps to “guide” and “provide guidance”, however, we already having trouble with information from FAQ’s, White Papers, and other guiding documents creeping into the requirements by auditing teams. The inclusion of “guiding information” in the text of the Standard itself may promote adding to requirements. Although helpful, I recommend removing this text from within the body of the Standard.
Response:		

8. Do you agree with the addition of a Guideline and Technical Basis Section to place technical materials and other related information that assists entities in understanding how to comply with the standard but does not contain mandatory actions/activities? Please explain.

Summary Consideration:

Organization	Yes or No	Question 8 Comment
Westchester County Board of Legislators		
Florida Municipal Power Agency (FMPA) and Some Members	No	Although FMPA agrees that a Guideline and Technical Basis document is important, FMPA has concerns about how this section might be used in compliance monitoring and enforcement. For instance, R4 has a time requirement somewhat embedded in the Guideline and Technical Basis that is not in the requirement in the standard: “The imminent threat process should be implemented in terms of minutes or hours as opposed to a longer time frame for interim corrective action plans”. How many minutes or hours? This adds ambiguity to the standard. If a time limit is desired, it should be in the requirement. There are other examples of items that could be interpreted as requirements in the Guidelines. It should be made clear what the purpose of the Guidelines is in compliance monitoring and enforcement. FMPA suggests publishing two documents in the same fashion that the Functional Model has two documents, one for the standards (e.g., the requirements), and another for technical guidance to the standards (e.g., the Guideline and Technical Basis section) to parallel the structure of the Functional Model and Functional Model Technical Document, which will help make the distinction between CMEP and guidance more distinct.
Response:		
American Transmission Company	No	ATC disagrees with the above statement that it only assists in understanding how to comply. ATC believes that parts of this section are written so they could be interpreted to contain mandatory actions/ activities. To demonstrate, see example on pg.15, R4, 2nd paragraph states...Two key elements of an acceptable imminent threat procedure are outlined below:..........) It should not be more than a preferred method for implementation or supporting how the TO can meet the standard. NERC needs to clarify how this section was intended to be used. (This as written could become part of a Compliance Audit process)Also, refer to ATC’s comment on this section in Question #3 above.
Response:		

Organization	Yes or No	Question 8 Comment
Bonneville Power Administration	No	Consider referencing ANSI A300 part 7 as best management practices for R3. It is currently referenced in the White Paper, and would lend more credibility to the standard if it was inserted in the text box for R3.
Response:		
ERCOT ISO	No	For the same reasons stated in the comments to Question 7, it should be expressly stated that this section is for information purposes only and is not part of the Standard Requirements. Compiling all of the "Information Only" materials into an Appendix would be the preferred method of organization.
Response:		
Northeast Power Coordinating Council	No	NPCC participating members do not believe that publishing more information as part of the standard is appropriate. For the same reasons as stated in the preceding response related to "Text Boxes" in question 7, any inconsistency may result in a conflict with a requirement. The information in the Guideline and Technical Basis section is valuable, however, and should be available to the industry in the form of guidelines. NPCC participating members suggest that NERC assemble a comprehensive set of "Guideline" documents into one bookmarked pdf publication to be updated as standards change. This will afford the industry a knowledge base that is not directly sanctionable for non-compliance, but a set of industry best practices, background, and reference for the standards development activities. Also, concern exists that FERC and Provincial governmental authorities will have jurisdiction over "Guidelines", and when the standard is approved it will become a mandatory "rule".
Response:		
Nebraska Public Power District	No	Same as item 7.
Response:		
CenterPoint Energy	No	See answer to Q3.
Response:		
GCPD	No	Should be separate documents. If located with the standard it will get used by the auditors as compliance issues. NO matter how much text you provide to the contrary it will become part of the standard over time.

Organization	Yes or No	Question 8 Comment
Response:		
Consolidated Edison Company of New York, Inc.	No	Since the SDT has developed a complete Technical Reference Document for this Standard, there seems to be redundancy with the Guideline and Technical Basis Section. This Standard has become too lengthy with all of the additional details and information that has been added. We prefer to have a shorter Standard and a more detailed stand alone supporting reference document.
Response:		
Orange and Rockland Utilities, Inc.	No	Since the SDT has developed a complete Technical Reference Document for this Standard, there seems to be redundancy with the Guideline and Technical Basis Section. This Standard has become too lengthy with all of the additional details and information that has been added. We prefer to have a shorter Standard and a more detailed stand alone supporting reference document.
Response:		
Cleco	No	The inclusion of the text implies additional requirements. Keep quidance to a separate paper.
Response:		
IRC Standards Review Committee	No	This change also requires some additional explanation. What level of importance will be given to such materials? If an SDT inserted a Best Practices document, does that allow auditors to refer to that document for purposes of holding an entity non-compliant? Are these materials there to help entities who do not know how to comply? If these materials are self-help guides, then it would be better to include them as URL references that are stored in the NERC library. That way there can be not confusion about whether the material is there as a self-help guide, or as a reference for auditors.
Response:		
FRCC Manager of Operations	No	We agree that this is valuable information and important to convey with the standard. This should be a separate companion document balloted, approved and posted with the standard but not be a part of the standard.
Response:		

Organization	Yes or No	Question 8 Comment
TO/TOP	No	We agree that this is valuable information and important to convey with the standard. This should be a separate companion document balloted, approved and posted with the standard but not as part of the standard.
Response:		
SERC OC Standards Review Group	No	We recommend that the text "grid reliability" be substituted for "Bulk Electric System" on page 6 of the draft.The inclusion of non-mandatory guidelines in a standard that will ultimately be approved by FERC gives undue credence to "guidelines" that will lead undoubtedly to mis-application by future compliance auditors. We suggest separation of this information from the mandatory reliability standard that will be filed at FERC. It could be held in a repository on the NERC website.
Response:		
Arizona Public Service Company	Yes	
Central Maine Power, Iberdrola USA	Yes	
Consumers Energy	Yes	
Duke Energy	Yes	
Exelon	Yes	
Manitoba Hydro	Yes	
North Carolina EMC	Yes	
Omaha Public Power District	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	

Organization	Yes or No	Question 8 Comment
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	
Tennessee Valley Authority	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	
Tampa Electric Company	Yes	Aids in improved understanding of FAC-003-2.
Response:		
FirstEnergy	Yes	Although we agree that guidelines are good to have and agree that having them in the body of the standards is convenient, we question how this section will be viewed from a compliance standpoint. We understand this section is not intended to be mandatory, but does that mean that regulatory authorities will only approve the other sections of the standard and not this section? Also, it should be clear and explicitly stated in the lead-in to this section that this is guidance which is not mandatory and enforceable. Additionally, terms such as "shall", "should", and "require" should not be used in the guidance section because the information presented in this section could be construed as mandatory by an auditor. An example of this is in the guidance information for Requirement R7 which states "Documentation is required when the annual work plan is adjusted...". This mandatory-type language should not be included in the Guidelines section.
Response:		
MRO's NERC Standards Review Subcommittee	Yes	Another good addition to the standard and will help clarify parts of the standard without referring to another document or set of guidelines.
Response:		
Southern California Edison Company	Yes	Assuming that the "Guideline and Technical Basis Section" will be retained and revised in future revisions to the standard, such information should prove very useful.

Organization	Yes or No	Question 8 Comment
Response:		
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	BGE agrees with the addition of a Guidance & Technical Basis section.
Response:		
JEA	Yes	Having the information in the same document makes the information more accessible to the entity attempting to comply with the standard.
Response:		
Ga Transmission Corp	Yes	I do however believe that each utility should have the flexibility to manage there program the way they feel is the most effective method. I do not want the technical basis section to limit options. Should this be in a white paper format?
Response:		
East Kentucky Power Cooperative, Inc.	Yes	I have no preference one way or the other on this issue.
Response:		
ITC Holding	Yes	ITC agrees with Guidelines and Technical Basis section, but recommend including useful Technical Reference actions and activities that would support defense-in-depth strategy. We also feel that to avoid any confusion with the applicability section and interpretations in the future, any references to the Bulk Electric System in the standard sections and guidance/technical reference document should be reviewed and changed.
Response:		
Entergy Services	Yes	Language should be added to the Guideline and Technical Basis Section to clarify or re-state that this section is for assisting entities in understanding how to comply with the standard but does not contain mandatory actions/activities, and a statement that entities are not required to use the information in the Guideline and

Organization	Yes or No	Question 8 Comment
		Technical Basis Section.
Response:		
Western Area Power Administrtaion	Yes	The format could be enhanced by moving the "Guidelines and Technical Basis" section forward to be included with the corresponding Requirement, Measure, and Rationale. Perhaps the "Guidelines and Technical Basis" could also be combined with the corresponding "Rationale" text box. This would be helpful because it is awkward flipping back and forth between these two sections when trying to fully understand a requirement.
Response:		
NERC Staff (12 staff members)	Yes	There is no language in the body of the standard to clarify that the information in the Guideline and Technical Basis Section of the standard is not subject to enforcement. We suggest revising the heading to “Application Guidelines.” This is the term that was originally proposed by the Results-based team and is the heading identified in the proposed Standard Processes Manual.
Response:		
SERC Vegetation Management Sub-committee	Yes	This format adds clarity and improves readability.
Response:		
Xcel Energy	Yes	This is all good information to add a depth of understanding for the user. It's not clear as to how modifications to the Guideline and Technical Basis would come about - it is the same as the standards revision process? Does this section replace the white paper? Will it actually be deemed to be part of the Standard? We are curious as to the legal weight if this is not part of the Standard and believe that key provisions are in this section. It seems it should be part of the Standard.
Response:		
Ameren	Yes	This is helpful information to have that does not clutter up the requirements and measurements. Under R6, the third paragraph, there is a typo: ..."230kv transmission lines at least once 'line' during the calendar year".
Response:		

Organization	Yes or No	Question 8 Comment
City of Tallahassee (TAL)	Yes	This is very useful information and will minimize misinterpretations by the entities and the compliance teams.
Response:		
Progress Energy Carolinas	Yes	This new section provides additional information and SDT rationale that is critical to understanding how to comply with the requirements in the standard and will also provide SDT intent/basis for the interpretation process when necessary. Progress Energy believes that any references to the Bulk Electric System in the standard sections and guidance/technical reference document should be reviewed and changed (e.g. “grid reliability”) to avoid confusion with the applicability section in this draft and avoid the potential for applicability interpretations once this version is adopted.
Response:		
Independent Electricity System Operator	Yes	This section should be placed in an appendix preceded by a statement that clearly states the purpose of the Section and indicates that the Guideline and Technical Basis Section does not in any way add to the requirements of the standard. Also, this section appears to be a summary of the Technical Reference Document but we could find no reference to the Technical Reference within the standard. This reference should be cited for the benefit of anyone seeking further detail.
Response:		
Western Area Power Administration - Upper Great Plains Region	Yes	WAPA - UGPR agrees with the concept of placing the background technical information in a separate section. We were a bit concerned with the Guideline for R7 because it seems to mandate many more items than were called for in the actual requirement in the body of the standard. Our belief is that the Guideline section should not infer or list any more requirements than the actual requirement dictates.
Response:		
Ad Hoc Group subteam formed to review draft standard	Yes	We agree with the additional material as an aide to entities to further understand the basis for the requirements. In this spirit the information should support compliant behavior and thus the reliability objectives of the standard.
Response:		
Dominion	Yes	While we agree that these can be useful, we are concerned about the ‘last minute’ change (March 24th) to the

Organization	Yes or No	Question 8 Comment
		technical reference document being used by those reviewing the materials for this project.
Response:		
Southen Company	Yes	Would it be better to have an official white paper associated with the standard rather than having this information in the standard? A white paper can be changed without seeking industry comments and approval from NERC, while information in the standard must go through the entire approval process. As it is structured now, information-only updates to the Technical Basis Section would require the entire standards approval process to be completed.
Response:		
American Electric Power (AEP)	Yes	Yes, although American Electric Power does question whether auditors will be able to avoid reading and applying such text.
Response:		
KCPL	No	I like information that helps to “guide” and “provide guidance”, however, we already having trouble with information from FAQ’s, White Papers, and other guiding documents creeping into the requirements by auditing teams. The inclusion of “guiding information” in the text of the Standard itself may promote adding to requirements. Although helpful, I recommend removing this text from within the body of the Standard.
Response:		

9. Do you prefer putting URL links to reference materials in the Guideline and Technical Basis Section, or do you prefer putting the additional technical/information materials in appendices, where needed, to supplement the Guideline and Technical Basis Sections? Please explain.

Summary Consideration:

Organization	Yes or No	Question 9 Comment
Central Maine Power, Iberdrola USA		
Westchester County Board of Legislators		
MRO's NERC Standards Review Subcommittee		If there is background information contained in a URL link pertaining to a particular Requirement, that link should be with the Requirement that it pertains to.
Response:		
Ad Hoc Group subteam formed to review draft standard		Judicious and correct use of citations should allow the proper documentation of references without the hazard of expired URLs or expansion from using appendices.
Response:		
Tennessee Valley Authority		No preference, either way will work.
Response:		
Consumers Energy	Prefer appendices	
Exelon	Prefer appendices	
PPL Electric Utilities Corporation (NCR00884)	Prefer appendices	

Organization	Yes or No	Question 9 Comment
South Carolina Electric and Gas	Prefer appendices	
TO/TOP	Prefer appendices	
Tucson Electric Power Co.	Prefer appendices	
Western Area Power Administrtaion	Prefer appendices	
Xcel Energy	Prefer appendices	
GCPD	Prefer appendices	Actually we prefer that they are separate from the standard entirely. See question 8.
Response:		
Cleco	Prefer appendices	An appendix ensures the information is available and original at the time the document it supports was prepared.
Response:		
ERCOT ISO	Prefer appendices	An Appendix would probably be easier to use, but either type of reference would suffice. Regardless of which is used, it should include a footnote that the information is “For Information Purposes Only” and are not a part of the Standard’s Requirements. If the information causes confusion, then it should be eliminated completely. Also, what types of materials are contemplated to be “reference materials”?
Response:		
Oncor Electric Delivery	Prefer appendices	Appendices would memorialize documents vs URL links to reference materials that may change over time. This Standard was crafted from “todays” point of view and background information. Reference material might change and the URL would point to material not validating the current form, logic, and background of the Standard.
Response:		

Organization	Yes or No	Question 9 Comment
Entergy Services	Prefer appendices	Appendices, or reference to a single site for all referenced material, would be the most helpful from the standpoint of keeping the information together and more readily available.
Response:		
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Prefer appendices	BGE prefers that such materials be included in the appendices.
Response:		
NERC Staff (12 staff members)	Prefer appendices	It is not clear what part of the standard is being balloted and what part is not. In addition, it is not clear what process will be used to modify the guideline/technical basis section of the standard. This needs to be determined before this standard can be balloted.
Response:		
FRCC Manager of Operations	Prefer appendices	Links can get broken - official records (ie. standards) need to stand alone.
Response:		
City of Tallahassee (TAL)	Prefer appendices	The fewer places I have to navigate to the better I like it. I find too many “broken” URLs. This will also make it easier when I download a “complete set” of standards from the NERC website.
Response:		
Dominion	Prefer appendices	Unless a ‘failsafe’ process is developed to insure URL links are keep up-to-date, preference is to locate all referenced materials within the standard (same URL). However, there are a number of ways that URL linkage could be done. One would be to locate all Guideline and Technical Basis documents on a webpage dedicated to such documents. This would allow URL linkage at a higher level than if there is URL linkage for each Guideline or Technical Basis document. This is probably the easiest to maintain. Another would be to link each Guideline or Technical Basis document referenced in a standard to the same URL as that standard. Maintaining URL linkage is probably medium. Yet another is to have the URL link to a webpage created specifically for that Guideline or Technical Basis document. This is likely

Organization	Yes or No	Question 9 Comment
		to be the hardest (require most effort) to maintain.
Response:		
CenterPoint Energy	Prefer appendices	URL links tend to change over time due to administrative requirements. Moving them to the appendix will avoid revisions to the Standard. See also answer to Q3 regarding the Guideline and Technical Basis Section.
Response:		
Florida Municipal Power Agency (FMPA) and Some Members	Prefer appendices	URLs can break
Response:		
Nebraska Public Power District	Prefer appendices	URLs change periodically.
Response:		
North Carolina EMC	Prefer appendices	Will need to put something in place to make sure that the links get properly updated if they change.
Response:		
Ameren	Prefer the inclusion of URL links	
Arizona Public Service Company	Prefer the inclusion of URL links	
Bonneville Power Administration	Prefer the inclusion of URL links	
Consolidated Edison Company of New York, Inc.	Prefer the inclusion of URL links	

Organization	Yes or No	Question 9 Comment
Duke Energy	Prefer the inclusion of URL links	
Ga Transmission Corp	Prefer the inclusion of URL links	
IRC Standards Review Committee	Prefer the inclusion of URL links	
Manitoba Hydro	Prefer the inclusion of URL links	
Omaha Public Power District	Prefer the inclusion of URL links	
Pepco Holdings, Inc. - Affiliates	Prefer the inclusion of URL links	
Southern California Edison Company	Prefer the inclusion of URL links	
Utility Risk Management Corporation	Prefer the inclusion of URL links	
Progress Energy Carolinas	Prefer the inclusion of URL links	Additional reference documents provide additional information that may be needed to understand how to comply and the basis of requirements, but they should not be included as appendices. The use appendices could result in a SDT process/effort for minor revisions to the reference document.
Response:		
American Transmission Company	Prefer the inclusion of URL links	Also see ATC's comment on "Guideline and Technical Basis Section" in Question #3 above.
Response:		

Organization	Yes or No	Question 9 Comment
Independent Electricity System Operator	Prefer the inclusion of URL links	In general the additional reference materials may make the document extremely voluminous so we prefer URL links.
Response:		
Northeast Power Coordinating Council	Prefer the inclusion of URL links	Links are preferable to alleviate the concerns expressed in question 8 above, especially with respect to FERC approval.
Response:		
JEA	Prefer the inclusion of URL links	No strong preference.
Tampa Electric Company	Prefer the inclusion of URL links	None
Western Area Power Administration - Upper Great Plains Region	Prefer the inclusion of URL links	None
Orange and Rockland Utilities, Inc.	Prefer the inclusion of URL links	Prefer the inclusion of URL links
Response:		
East Kentucky Power Cooperative, Inc.	Prefer the inclusion of URL links	Provides for clarity and readability.
Response:		
Southen Company	Prefer the inclusion of URL links	See answer to number 8.
Response:		

Organization	Yes or No	Question 9 Comment
American Electric Power (AEP)	Prefer the inclusion of URL links	The use of URL links is probably most appropriate for an increasingly web-based reference repository.
Response:		
SERC OC Standards Review Group	Prefer the inclusion of URL links	This format adds clarity and improves readability.
Response:		
SERC Vegetation Management Sub-committee	Prefer the inclusion of URL links	This format adds clarity and improves readability.
Response:		
ITC Holding	Prefer the inclusion of URL links	URL links provide immediate access, are less cumbersome, and usually provide additional research material when accessed.
Response:		
FirstEnergy	Prefer the inclusion of URL links	We prefer URL links. Although, we are not clear what this question is asking regarding "additional technical/information materials". Is the team referring to "supplemental" reference documents such as the technical reference white paper that was recently posted for stakeholder review on March 24, 2010? If so, we agree that supplemental reference material be included through URL links, perhaps at the end of the "Guidelines and Technical Basis" section of the standard.
Response:		
KCPL	Prefer appendices	Although a good idea generally, too many times URL links change name or something else that makes the imbedded link unusable or takes you to the wrong place. Having an appendix ensures the information is available and original at the time the document it supports was prepared.
Response:		

10. Do you agree with the addition of the Background Section to allow provision of background information, and to elaborate on the reliability-related drivers for the standard/change? Please explain.

Summary Consideration:

Organization	Yes or No	Question 10 Comment
Westchester County Board of Legislators		
ERCOT ISO	No	Again, it is preferable to include this type of information in an Appendix as long as it is made clear that this is additional information and is not a part of the Standard's Requirements. However, if there is a chance that the additional information included in the Appendix is going to cloud the Requirements spelled out in the Standard, then our preference is to eliminate the additional information completely.
Response:		
SERC OC Standards Review Group	No	Inclusion of a background section in a document that will be approved wholly by FERC give undue credence and weight to statements which may be included that are not necessarily factual 100% of the time. For example, the first sentence of the last paragraph of the background section reads as follows: "Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating." Obviously, woody stems do not grow during the dormant season, yet the background asserts that it does. There are other areas in this sentence that are not completely factual and should not be in a reliability standard. We recommend that the text "grid reliability" be substituted for "Bulk Electric System" on page 6 of the draft.
Response:		
Consumers Energy	No	Not necessary.
Response:		
Northeast Power Coordinating Council	No	NPCC participating members believe this is more informational and appropriate on the individual standard's NERC Website "Under Development" page, in an announcement, cover letter, or to be distributed with the standard drafts.

Organization	Yes or No	Question 10 Comment
Response:		
Nebraska Public Power District	No	Same as item 7.
Response:		
CenterPoint Energy	No	See answer to Q3.
Response:		
Florida Municipal Power Agency (FMPA) and Some Members	No	The background belongs in the Guidelines and not as part of the standard.
Response:		
FRCC Manager of Operations	No	The background section should be re-named "Technical Basis". Trim content and leave only the first and last paragraphs. In addition, all 5 paragraphs of the section as written should be moved to the front of the Guidelines and Technical Basis document as a "Background" section of that separate document. NERC should limit its use of "background" information within the reliability standard itself.
Response:		
TO/TOP	No	The background section should be re-named "Technical Basis". Trim content and leave only the first and last paragraphs. In addition, all 5 paragraphs of the section as written should be moved to the front of the Guidelines and Technical Basis document as a "Background" section. NERC should limit its use of "background" information in reliability standards.
Response:		
Cleco	No	The inclusion of the text implies additional requirements. Keep quidance to a separate paper.
Response:		
Exelon	No	This information should be in appendices or reference documents available on the NERC standards site.

Organization	Yes or No	Question 10 Comment
Response:		
Ameren	Yes	
Arizona Public Service Company	Yes	
Bonneville Power Administration	Yes	
Central Maine Power, Iberdrola USA	Yes	
City of Tallahassee (TAL)	Yes	
Duke Energy	Yes	
East Kentucky Power Cooperative, Inc.	Yes	
Ga Transmission Corp	Yes	
JEA	Yes	
Manitoba Hydro	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
North Carolina EMC	Yes	
Omaha Public Power District	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	

Organization	Yes or No	Question 10 Comment
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	
Southen Company	Yes	
Tennessee Valley Authority	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	
Western Area Power Administrtaion	Yes	
SERC Vegetation Management Sub-committee	Yes	Allows for a more informed interpretation of the standard.
Response:		
American Electric Power (AEP)	Yes	American Electric Power agrees with this change.
Response:		
American Transmission Company	Yes	ATC agrees that the Background Section is helpful; however, NERC should define its purpose and goal. What is currently written is more than necessary to be included in this standard.
Response:		
Dominion	Yes	Dominion agrees but suggests it be moved towards end (suggest between Administrative and Guideline/Technical basis sections).

Organization	Yes or No	Question 10 Comment
Response:		
Ad Hoc Group subteam formed to review draft standard	Yes	Great help in showing intent and reliability goal of the standard.
Response:		
Southern California Edison Company	Yes	Including a background section should prove useful for future editions. However, at some point such information could be made accessible through URL links.
Response:		
ITC Holding	Yes	ITC agrees with the addition of Background Section
Response:		
GCPD	Yes	May help in iterpretations and in explaining to stakeholders in our organizations.
Response:		
Tampa Electric Company	Yes	None
Western Area Power Administration - Upper Great Plains Region	Yes	None
Progress Energy Carolinas	Yes	Progress Energy agrees and believes that the background section will allow relevant background information that provided direction/guidance for the SDT to be readily available after the standard revision is adopted.
Response:		
Entergy Services	Yes	The Background Section is helpful, but the last sentence states....."Thus, this Standard's emphasis is on vegetation grow-ins.". This statement seems to conflict with the outage Category 2 "Fall In" classification, even though it is a fall in from within the ROW.

Organization	Yes or No	Question 10 Comment
Response:		
Xcel Energy	Yes	The Background section should be moved to the back, in front of the Guideline and Technical Basis.
Response:		
IRC Standards Review Committee	Yes	This background is important for insertion at the beginning of a SAR. But for a standard-posting, it is suggested that this section is redundant and better inserted after the requirement and measures with the other Administrative materials.
Response:		
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	This makes sense to BGE.
Response:		
NERC Staff (12 staff members)	Yes	This provides a context for the requirements and is very beneficial in understanding the intent of the standard.
Response:		
Independent Electricity System Operator	Yes	This section expands on the purpose statement and will promote a uniform understanding of the fundamental drivers for the standard and its requirements, as well as its philosophy and scope.
Response:		
Consolidated Edison Company of New York, Inc.	Yes	We agree but believe the Background Section should be situated before the Applicability Section in the revised Standard and redundant verbiage should be removed.
Response:		
Orange and Rockland Utilities, Inc.	Yes	We agree but believe the Background Section should be situated before the Applicability Section in the revised Standard and redundant verbiage should be removed.

Organization	Yes or No	Question 10 Comment
Response:		
FirstEnergy	Yes	We agree that a Background section is beneficial. However, we believe it may be more appropriate to move this information to the Guidelines section as a lead-in. Also, we suggest a rewording of the first sentence of the first paragraph on Pg. 2 which states: "Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations". We agree that vegetation can contribute to outages, but it cannot be the sole cause of major outages. Major outages can be prevented if other measures required by other NERC standards are implemented when vegetation causes a line or other equipment to malfunction. We suggest a rewording of this statement as follows: "Interference between vegetation and transmission lines located on many types of land have contributed to significant outages and operational challenges."
Response:		
KCPL	No	I like information that helps to “guide” and “provide guidance”, however, we already having trouble with information from FAQ’s, White Papers, and other guiding documents creeping into the requirements by auditing teams. The inclusion of “guiding information” in the text of the Standard itself may promote adding to requirements. Although helpful, I recommend removing this text from within the body of the Standard.
Response:		

11. Do you agree with the addition of an Administrative Procedure Section to place administrative/procedural requirements that are contained in the existing standards but which do not meet the results-based or risk-based criteria? Please explain.

Summary Consideration:

Organization	Yes or No	Question 11 Comment
ERCOT ISO		
North Carolina EMC		
Westchester County Board of Legislators		
Consumers Energy	No	
Nebraska Public Power District	No	Administrative requirements should not be included in the Standard, they may be construed unintentionally as a requirement.
Response:		
GCPD	No	Anything not directly associated with the compliance requirements or for help with interpretations should not be in the standard.
Response:		
Northeast Power Coordinating Council	No	As stated earlier, NPCC participating members don't understand if this section holds sanctionable requirements, and if so under what authority. Administrative items are best left to the ROP or Compliance documents. A results based standard's primary focus should be on the requirements, and the goal or reliability objective. Taking administrative requirements out of the formal requirements section, adding them to another section, and still deeming them to be requirements is of no value to reducing the administrative burden on the industry. This makes the implementation of the standard more burdensome due to the fact that these additional "requirements" now reside in different places in the standard document. NPCC participating members suggest if these are truly valid requirements they need to be together with the other requirements. If they do not meet the results based criteria, and were included in this "Administrative Procedure" section

Organization	Yes or No	Question 11 Comment
		strictly because of that, then they need to reside in another document. Their continued appearance in the document dilutes the integrity of the results based standard initiative.
Response:		
Exelon	No	Exelon is concerned this will raise questions concerning what criterion separates an administrative requirement from a results or risk based requirement. How are administrative requirements to be treated in the CMEP?
Response:		
CenterPoint Energy	No	It is not clear if the Administrative Procedure is a mandatory activity. It would be helpful if the intent of this section was stated within the Standard.Also, this section in not parallel with the Rating and Rated Electrical Operating Conditions exception contained in R1 and R2. We recommend the following parallel wording for the first paragraph of this section:"The Transmission Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying certain Sustained Outages of the categories defined below, while operating within the Rating and Rated Electrical Operating Conditions, determined by the Transmission Owner to have been caused by vegetation that includes, as a minimum, the following:"Also, the categories listed in this section do not have parallel language to M1 and M2. We recommend that this section should adopt the wording in M1 and M2 for the Sustained Outages to be reported. Currently, Category 2 and Category 4 do not distinguish between an IROL and Major WECC Transfer Path. This may become a tracking problem since they have different Violation Risk Factors. If this is not important, then Category 1A and 1B can be combined.
Response:		
Consolidated Edison Company of New York, Inc.	No	It is somewhat confusing to have sanctionable requirements located in other sections of the Standard outside of 'Requirements and Measures.' The section title 'Administrative Procedure' is somewhat misleading; if it was renamed 'Administrative Requirements' we feel it would be clearer to the industry.
Orange and Rockland Utilities, Inc.	No	It is somewhat confusing to have sanctionable requirements located in other sections of the Standard outside of 'Requirements and Measures.' The section title 'Administrative Procedure' is somewhat misleading; if it was renamed 'Administrative Requirements' we feel it would be clearer to the industry.
Response:		

Organization	Yes or No	Question 11 Comment
SERC OC Standards Review Group	No	Reporting Outages is not a part of Vegetation Mgmt. Therefore, this reporting belongs in an Administrative Section or possibly via a NERC 1600 request. In no circumstance should it be a Requirement of the standard. In the last paragraph this section appears to place a requirement on a regional reliability entity: “The Regional Entity will report the outage information provided by Transmission Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.” Was this really intended? What if the RE fails to make a report?
Response:		
IRC Standards Review Committee	No	Some additional explanation is needed. If the requirement is to do inspections, and compliance is measured on that basis only then the Administrative Section is OK. If the entity is mandated to also meet the actions specified in the Administrative Section, then the change is not acceptable. This standard's example administrative section is introducing new requirements into the standard, and those requirements should be in the standard. In short, if there is a reliability requirement than that is what should be mandated. The idea of mandating administrative items that are often designed to make auditing (not operations or planning) simpler should not be mandated.
Response:		
FRCC Manager of Operations	No	The "Administrative" section needs to be streamlined - remove the first 2 paragraphs - quarterly reporting is no longer required and would be an administratively redundant process to the self-reporting of outages. Leave the outage categories to support consistent self-reports. Delete last paragraph - reporting by the Regional Entities to NERC is a delegated function that should be governed by the delegation agreements, rules of procedure or other internal ERO process, not within a reliability standard since REs and the EROs are not users, operators, etc of the BPS.
Response:		
TO/TOP	No	The "Administrative" section needs to be streamlined - remove the first 2 paragraphs - quarterly reporting is no longer required and would be an administratively redundant process to the self-reporting of outages. Leave the outage categories to support consistent self-reports. Delete last paragraph - reporting by the Regional Entities to NERC is a delegated function that should be governed by the delgation agreements, rules of procedure or other internal ERO process, not a reliability standard.
Response:		

Organization	Yes or No	Question 11 Comment
Ad Hoc Group subteam formed to review draft standard	No	The administrative procedure section is appropriate under results-based requirements. However, we believe that reporting requirements established under other methods, such as the CMEP, may be confused by including it. It is unclear how non-conformance with administrative procedures would be handled. Perhaps administrative procedures would be better handled under ROP Section 1600 data requests or other Rules.
Response:		
Cleco	No	The inclusion of the text implies additional requirements. Keep quidance to a separate paper.
Response:		
Florida Municipal Power Agency (FMPA) and Some Members	No	The reporting requirements really boil down to a self-reporting or self-certification process since the only items to report would be violations to the standard. If such quarterly reporting is desired, it is really a self-certification process and should be governed by that process and not through a separate Administrative Procedure.FMPA recommends deleting the last paragraph - reporting by the Regional Entities to NERC is a delegated function that should be governed by the delegation agreements, rules of procedure or other internal ERO process, not within a reliability standard since REs and the EROs are not users, operators, etc of the BPS, and are not designated in the Applicability section.
Response:		
Ameren	Yes	
Arizona Public Service Company	Yes	
Bonneville Power Administration	Yes	
Central Maine Power, Iberdrola USA	Yes	
City of Tallahassee (TAL)	Yes	
Dominion	Yes	
Entergy Services	Yes	

Organization	Yes or No	Question 11 Comment
Ga Transmission Corp	Yes	
Manitoba Hydro	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
NERC Staff (12 staff members)	Yes	
Omaha Public Power District	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	
Southen Company	Yes	
Southern California Edison Company	Yes	
Tennessee Valley Authority	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	
Xcel Energy	Yes	Are we to understand that the requirements listed in the Administrative section are not sanctionable from a NERC compliance perspective?

Organization	Yes or No	Question 11 Comment
Response:		
American Transmission Company	Yes	ATC feels this adds good will on the part of the entity to submit necessary reports, however, ATC requests clarification whether this section is subject to NERC violations. (Currently not listed in Table 1 Time Horizons, VRFs and VSLs)
Response:		
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	BGE agrees with addition of an Administrative Procedure section.
Response:		
Duke Energy	Yes	During the WEBINAR, a question was raised regarding how failure to meet an Administrative/Procedural requirement would be addressed by the Regional Entity. Can the Standard Drafting Team prepare a response to the question?
Response:		
JEA	Yes	However, it needs to be made clear whether this is subject to audit, and whether failure to meet the requirement is subject to the same or different enforcement procedures as the numbered requirements in the standard.
Response:		
East Kentucky Power Cooperative, Inc.	Yes	I do not believe that reporting of outages is a part of development and implementation of a Vegetation Management Plan. I fail to see how it brings value to the standard.
Response:		
ITC Holding	Yes	ITC agrees that the “administrative role” such as outage reporting; shouldn’t be a reliability requirement and are more appropriately defined as an administrative procedure. We would also like some clarification on whether this section of the standard is subject to NERC violations. Currently it’s not listed in Table 1 Time Horizons, VRFs and VSLs

Organization	Yes or No	Question 11 Comment
Response:		
Western Area Power Administration - Upper Great Plains Region	Yes	None
Tampa Electric Company	Yes	Not sure why separating 1.A & 1.B is preferred over 1,2,3,4?
Response:		
Progress Energy Carolinas	Yes	Progress Energy agrees that “Administrative” functions such as outage reporting should not be listed as a reliability requirement and are more appropriately defined as an administrative procedure. (Outage reporting is an administrative function that does not directly improve reliability which should be the focus of reliability standard requirements.)NERC has other formal information request procedures in place (such as a NERC 1600 request), if that becomes necessary to ensure outage reporting.
Response:		
SERC Vegetation Management Sub-committee	Yes	Reporting Outages is not a part of Vegetation Mgmt. Therefore, this reporting belongs in an Administrative Section or possibly via a NERC 1600 request. In no circumstance should it be a Requirement of the standard.
Response:		
Western Area Power Administrtaion	Yes	The Administrative Procedure section could be moved forward following the Background section to better introduce the general administrative overview for what would then become the following Requirements, Measures, etc. These general administrative and procedural requirements are more easily overlooked when they included at the back of the Standard.
Response:		
American Electric Power (AEP)	Yes	This addition is acceptable
Response:		
Independent Electricity System	Yes	This section imposes an additional reporting requirement but there is no associated VRF or VSL. Is this

Organization	Yes or No	Question 11 Comment
Operator		intentional? How will failure to report on time be treated? This is unclear as is the significance of any such Administrative "Requirements" within the standard, in general. Is the intention to establish separate procedures to govern the administrative and reporting obligations of registered entities under the Rules of Procedure?
Response:		
FirstEnergy	Yes	We agree with the Administrative Procedure Section. Monetary fines should not be imposed for noncompliance with administrative requirements.
Response:		
KCPL	No	It is too easy to unintentionally infer or introduce something that is not intended to be a requirement, but gets interpreted as a requirement in this section. Standards should be clear in what is a requirement and what is helpful information. If these are requirements, then propose them as requirements. If not, then remove to another guiding document.
Response:		

12. Is there any other information that should be included in the standard document? If so, please explain why you feel that this information should be included.

Summary Consideration:

Organization	Yes or No	Question 12 Comment
ERCOT ISO		
FRCC Manager of Operations		
North Carolina EMC		
TO/TOP		
Westchester County Board of Legislators		
Ad Hoc Group subteam formed to review draft standard	No	
American Transmission Company	No	
Bonneville Power Administration	No	
City of Tallahassee (TAL)	No	
Cleco	No	
Consolidated Edison Company of New York, Inc.	No	
Consumers Energy	No	

Organization	Yes or No	Question 12 Comment
Dominion	No	
Duke Energy	No	
East Kentucky Power Cooperative, Inc.	No	
Exelon	No	
Florida Municipal Power Agency (FMPA) and Some Members	No	
Ga Transmission Corp	No	
Independent Electricity System Operator	No	
ITC Holding	No	
JEA	No	
Manitoba Hydro	No	
Nebraska Public Power District	No	
NERC Staff (12 staff members)	No	
Northeast Power Coordinating Council	No	
Oncor Electric Delivery	No	
Orange and Rockland Utilities, Inc.	No	

Organization	Yes or No	Question 12 Comment
Pepco Holdings, Inc. - Affiliates	No	
PPL Electric Utilities Corporation (NCR00884)	No	
South Carolina Electric and Gas	No	
Southern California Edison Company	No	
Tennessee Valley Authority	No	
Tucson Electric Power Co.	No	
Utility Risk Management Corporation	No	
Western Area Power Administrtaion	No	
Tampa Electric Company	No	All areas have been addressed and clarified as needed.
Response:		
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	No	BGE feels no other information is necessary for inclusion.
Response:		
American Electric Power (AEP)	No	None
Western Area Power Administration - Upper Great	No	None

Organization	Yes or No	Question 12 Comment
Plains Region		
GCPD	No	Too much already.
Response:		
Omaha Public Power District	Yes	
SERC OC Standards Review Group	Yes	As suggested in comment six, an improvement would be also listing the applicable table rows with each requirement which consolidates all pertinent info with the requirement. Also, adding the penalty matrix would facilitate discussions with property owners/agencies resisting maintenance activates. This standard indicates a lack of recognition that vegetation outages are not necessarily reliability events. In the quest for improved reliability, spending the money necessary to achieve perfect compliance with R2, as stated, either will increase customer rates unnecessarily or cause the misallocation of maintenance funding away from maintenance activities that have a substantially higher impact on reliability.
Response:		
SERC Vegetation Management Sub-committee	Yes	As suggested in comment six, an improvement would be also listing the applicable table rows with each requirement which consolidates all pertinent info with the requirement. Also, adding the penalty matrix would facilitate discussions with property owners/agencies resisting maintenance activates.
Response:		
Arizona Public Service Company	Yes	Clearance 1 needs to be put back into this requirement as written. This is a vegetation management standard and there needs to be clear direction on how the system is going to be maintain at the time of maintenance. This ensures a clear direction to the utility the system has to be maintained. ANSI A-300 part 1 and 7 needs to be a requirement within the standard. Following this consensus agreement within the Professional Utility Vegetation Management sector outlines a process for providing a reliable transmission system. At a minimum ANSI A-300 part 1 and 7 should be incorporated into the Guideline and Technical Basis Section as a resource for compliance with this standard. Prudence would dictate that it be adopted into this draft as the foundation of any transmission vegetation management program as it is the accepted standard for professionals who are responsible for managing vegetation for electric utilities.Personnel qualifications need to be included in the standard and should include minimum measures such that there is consistency across the industry. This ensures that personnel are qualified and will have ongoing training and education in utility vegetation management. For example: The person who manages the field operation should have at least 5

Organization	Yes or No	Question 12 Comment
		years experience in vegetation management be an International Society of Arboriculture Certified Arborist and a Utility Specialist.
Response:		
Ameren	Yes	In 4.3.1, suggest that "ice" be included in circumstances beyond the reasonable control of a TO in addition to the other "acts of God".
Response:		
Entergy Services	Yes	More clarifying language throughout the document would be helpful.
Response:		
Progress Energy Carolinas	Yes	None, other than the comment about potential improvements in question #6.
Response:		
IRC Standards Review Committee	Yes	Regarding the new format, the idea of using “Informal Comment Periods” may be useful in speeding up the process of developing standards, but it also introduces a potential for a given Team to ignore valuable comments (either because the issue is unknown to them, or because the issue does not agree with their ideas). How will the Standards Committee or others ensure the quality of the process does not suffer in this way? What type of review process is contemplated to detect such behavior? Having the Formal comments at the end of the process may prevent subject matter experts (SME) from seeing the comments and perspectives of other SMEs. The SRC suggests that all comments (both formal and informal) be posted immediately for all to review.
Response:		
Xcel Energy	Yes	See comments to #1, #7 and #13 of this form
Response:		
FirstEnergy	Yes	See our other comments.

Organization	Yes or No	Question 12 Comment
Response:		
Central Maine Power, Iberdrola USA	Yes	Table 2 expand footnote - State that table 2 is intended as a buiding block to develop clearance at time of vegetation management work. See TVMP for clearances.
Response:		
CenterPoint Energy	Yes	The detailed rationale for the required one year inspection cycle in R6 should be included in the Technical Reference. The explanation provided in the Rationale that it “seems to be reasonable” and in the Technical Reference that it is “reasonable based on upon average growth rates across North America and common utility practice” are unfounded and arbitrary without a specific reference to a North American study. The Technical Reference should contain an example diagram of “the portion of the ROW where the corridor edge zones are designated by regulatory bodies for vegetation to exist” taken from the examples in the Definition of Terms Used in Standard section. It is unclear how this example should be interpreted for compliance should a Sustained Outage occur from vegetation growing within this zone. It is common for regulatory bodies to push utilities to plant trees or maintain trees within transmission rights of way to “hide the lines”, and it is unclear if this example is attempting to encourage such practice by regulatory bodies at the sacrifice of reliability.In general, the Technical Reference should contain more specific examples of violations of the Requirements and highlight specific exceptions related to vegetation related outages.The background and basis for adding the term “Active Transmission Line Right-of-Way” should be added to the Technical Reference.The background and basis for 4.2.4 that excludes the Standard from applying to fenced substations should be added to the Technical Reference.Just as the force majeure statement (4.3.1) was moved to the Applicability section of the Standard, the exception for applicability beyond the Rating and Rated Electrical Operating Conditions should be included in the Applicability section as well. Currently, it is only included in R1 and R2. It should be made clear if the other Requirements and Measurements must consider conditions beyond the Rating and Rated Electrical Operating Condition.Within the Requirements and Measures section there should be subheadings for each type of Requirement, performance-based, risk based, and competency-based. This classification is only indicated in the Technical Reference.
Response:		
MRO's NERC Standards Review Subcommittee	Yes	The NSRS believes a section for definitions and abbreviated terms such as, Active ROW, MVCD, and WECC is needed. Also, See comment above in Question 9 on URL links.
Response:		

Organization	Yes or No	Question 12 Comment
Southen Company	Yes	We feel a definition of Category 3 outages (non reportable outages) should be included under the administrative procedures. Although these outages are not reportable, this would provide a mechanism for classifying these outages so the utility can maintain evidence of its investigation and the rationale for not reporting them.
Response:		
KCPL	No	

13. Do you have any other comment regarding the draft FAC-003-2 Transmission Vegetation Management standard that have not been addressed above? If yes, please provide a reference to the section, requirement, or subrequirement that you believe should be changed, added or deleted and the rationale for your proposal.

Summary Consideration:

Organization	Yes or No	Question 13 Comment
Entergy Services		
ERCOT ISO		
TO/TOP		
American Electric Power (AEP)		American Electric Power suggests replacing the term "Minimum Vegetation Clearance Distance" with "Critical Vegetation Clearance Distance." The use of "minimum" suggests that the minimum is acceptable. However, in dealing with landowners or land managers, we may not be able to negotiate any more than the minimum. "Critical" would help convey the sense that the distance borders on dangerous unacceptability.
Response:		
Central Maine Power, Iberdrola USA	No	
Consumers Energy	No	
East Kentucky Power Cooperative, Inc.	No	
IRC Standards Review Committee	No	
Manitoba Hydro	No	
Pepco Holdings, Inc. -	No	

Organization	Yes or No	Question 13 Comment
Affiliates		
PPL Electric Utilities Corporation (NCR00884)	No	
South Carolina Electric and Gas	No	
Southern California Edison Company	No	
Tennessee Valley Authority	No	
Tucson Electric Power Co.	No	
Tampa Electric Company	No	None
FRCC Manager of Operations	Yes	- Applicability Section 4.3 - use the term "Exemptions" instead of "Other" as it is more descriptive.- As noted earlier - Applicability Section 5 - use the term "Technical Basis" instead of "Background" and streamline by removing paragraphs 2, 3 and 4.- R
Response:		
American Transmission Company	Yes	(a) R1 and R2 (pg.7) - What is meant by “to avoid a Sustained Outage”. Could be argued that a grow-in that does not cause a Sustained Outage is acceptable. (Could this be a FERC issue?)(b) R5 (pg.9) - ATC believes the term “temporarily” should be stricken from the requirement. This leaves too much to interpretation and does not add to the requirement(c) R6 (pg.9) - The descriptive timeframe “at least once per calendar year” is used. What does this mean? Every 365 days or a 12 month period within a calendar year? NERC needs to define this.(d) R4 (pg.15 in the Guideline and Technical Basis) - The term “verified knowledge” is used which does not seem consistent with the definition of “Verified Knowledge” in R4 Rationale on pg.8.(e) R4 (pg.16 in the Guideline and Technical Basis) - The term “responsible control center” is used and further defined. ATC believes this is the Transmission Operator. This should either be moved to the “Definitions of Terms” section or to R4 of the standard where the term is used.

Organization	Yes or No	Question 13 Comment
Response:		
Western Area Power Administrtaion	Yes	1) It is suggested that the word "located" in the third bullet in Measure 1 and Measure 2 be replaced with the word "originating". As worded, M1 or M2 could be interpreted to mean that vegetation originating outside of the right-of-way which blows or sways into contact with conductors "located inside the ... right-of-way" would be evidence of a violation of R1 or R2. Utilities generally are very limited in their ability to manage vegetative conditions outside of their right-of-ways.2) Please reference the comments under Question 2 above regarding the incompleteness of requirements R3 and R7 in fully replacing the CCZ management concepts utilized in the Draft 1 version of the proposed FAC-003-2.3) The requirement R4 Guidelines and Technical Basis narrative is inconsistent with requirement R4. Specifically, in the Guidelines and Technical Basis section the second paragraph's introductory sentence identifies a requirement for an imminent threat procedure, and the second bullet in this paragraph identifies a need to identify vegetation related conditions that warrant a response. Neither of these items are a requirement of R4 as currently written. R4 only speaks to the notification of the responsible control center when it has verified knowledge of a vegetation imminent threat condition.4) The requirement R7 Guidelines and Technical Basis section is written with an inappropriate bias towards very extensive or time based vegetation maintenance programs. Comments received from previous draft standard reviews have revealed that there are many other effective program approaches being utilized by the industry. It is suggested that this section be revised to broaden its scope to incorporate these other program approaches.
Response:		
Ga Transmission Corp	Yes	1) I would like further examples of inactive portions of corridors. For example would a ten foot buffer strip that is in addition to a normal width to stay off a property line but is included in an easement plat but not cleared be considered inactive corridor or not? 2) The MVCD definition may not be realistic in its wording. Many utility companies may not be able to maintain these clearances at "design of Transmission Facility". This needs further definition maybe "NESC moderate wind". Many utilities in coastal areas will design lines for high sustained winds due to hurricanes these clearances may not be possible to maintain under these conditions however the line may be designed to with stand these winds.
Response:		
FirstEnergy	Yes	1. Requirements R1 and R2 - We do not agree with the "zero tolerance" for real-time observation of encroachments that do not cause an outage. When discovered, most Transmission Owners (TO) take immediate action to alleviate encroachments and it is not appropriate to be fined for taking immediate action when no outage has occurred. Therefore, a violation should only occur when the TO has not immediately alleviated the situation within 24 hours. We suggest the following change to the first bullet in Measures M1 and M2: "Real-time observation of encroachment into the MVCD that is not corrected within 24 hours."2. Measurement M1 and M2 - For additional clarity, we suggest

Organization	Yes or No	Question 13 Comment
		adding the following wording from Guideline and Technical Basis into M1 and M2 - "Brief encroachment by falling vegetation are not considered a violation."3. Requirement R4 - Since the intent of this requirement is the immediate notification of an imminent threat, we suggest adding the word "immediately" between "shall" and "notify".4. Requirement R5 - We suggest removing the term "temporarily" in the requirement. Some constraints faced by Transmission Owners are permanent and appropriate alternate action is permanently implemented. 5. Requirement R7 - Although we agree that the TO should be allowed to adjust the plan, the use of the term "flexible" is subjective. Additionally, the phrase "to ensure no vegetation encroachments occur within the MVCD" is redundant with the other requirements of the standard. Therefore, we suggest revising the wording of Requirement R7 to the following: "Each Transmission Owner shall implement an annual vegetation work plan. Adjustments to the work plan to defer work beyond the calendar year are acceptable and shall be documented."6. Coordination between Project 2007-07 and 2010-07 - Since the TO-GO interface team has identified the need for Generator Owner (GO) applicability in the FAC-003 standard, we believe that these two drafting teams should coordinate the addition of the GO into this Version 2 of FAC-003. It would not seem sensible to revise Version 1 of FAC-003 to include the GO while Version 2 is developed and approved without applicability to the GO.7. Compliance Section - Under "Additional Compliance Information", we suggest removing the parenthetical phrase "See Administrative Procedure" and replace with "None". Since the Administrative Procedure is not part of the requirements, it is not sanctionable and should not be included in the Compliance Section.
Response:		
MRO's NERC Standards Review Subcommittee	Yes	1. Need definition for the phrase “Major WECC Transfer Paths”.2. In question 2 of the comment form, it refers to the “bulk power system.” This standard does not cover the bulk power system, it covers lines above 200kV and certain ones below 200kV.
Response:		
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	4.2.4 States that the Standard is not applicable to “...to Facilities .... located inside the fenced area of a switchyard, station or substation”. This implies that anything within the fenced area of a switchyard, substation or power plant does not fall within the jurisdiction of FAC-003-2. Some fenced in areas could be very large and susceptible to vegetation encroachments issues.4.3.1 Suggest including in the Force Majeure government a phrase referencing government interference, such as “Federal, State or other regulatory interference, including legal or other legislative actions, that prevents performance to comply with this reliability standard.”M1 & M2 bullet: “Real-time observation of encroachment into the MVCD” implies that real-time observation of vegetation encroachment ensures reliable operation the Bulk Electric System. The reliability standard objective states;”To improve the reliability of the electric Transmission system by preventing those vegetation related outages that could lead to Cascading.”However, real time observation of current operating conditions provides no assurance that vegetation will not lead to outages. BGE recommends removing the language. If an inspector finds vegetation encroaching into the MVCD during a visual inspection he / she

Organization	Yes or No	Question 13 Comment
		should immediately initiate an Immediate Threat Notification. Therefore, this measure has no value.Disagree with R6. - Inspection Frequency. Very prescriptive. Please consider allowing TO's to select an annual frequency that best fits their requirements, such as calendar year, every growing season, every non-growing season, etc. BGE currently defines their inspection frequency as annually during the non-growing season, October 1 to May 1. BGE believes inspecting during the dormant season is a best practice due to the ability of the inspector to identify vegetation defects, especially off the ROW, which could be hidden during the growing season due to foliage, canopy cover, etc. Also, if a utility elects to leverage an advance technology, such as LiDAR, it provides the most effective results when LiDAR is utilize during the growing season, therefore allowing the results of the advance technology to enhance the fall to spring inspection cycle. All of the above comments are submitted on behalf of: - Baltimore Gas & Electric Company - Constellation Energy Group, Inc. - Constellation Power Source Generation, Inc. - Constellation Energy Commodities Group, Inc. - Constellation New Energy, Inc. - Constellation Energy Nuclear Group, Inc.
Response:		
Arizona Public Service Company	Yes	APS objects to number 3 Objectives statement. This is the only reliability standard that has at its Objective to prevent vegetation related outages that could lead to cascading. This is a reliability standard and its objective needs to be: "To improve the electric Transmission system by preventing vegetation related outages." Requirement 6: To ensure reliability the TO's are responsible for doing an annual inspection. You either do it or don't and if you don't finish it you should be held accountable. There shouldn't be a lower VSL because you didn't finish all of it. This is poor planning on the utilities part.Requirement R7: When developing the annual work plan the Transmission Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Transmission Owners may also need to consider those special landowner requirements as documented in easement instruments. There needs to be parameters for the TO to show they allowed time for procedural requirements. An example, some land agencies will give you permission to perform work in as little time as two weeks and others can take two years. Even within the same land agency the timing of approvals is a moving target. APS recommends the TO must show documentation it submitted their Vegetation Management Plan to the land agency at least 120 days prior to the required start date. If the land agency doesn't respond within this time frame and the utility can not perform the work they shouldn't be held responsible.
Response:		
JEA	Yes	Generally, I believe this document is a huge improvement. The requirements are much clearer and easier to implement than some versions from the past. I do not understand why R7 is still in this standard however. It appears to be a requirement whose purpose is only to dictate HOW an entity must document its implementation of its vegetation management program. Thus, I believe this requirement should be removed.

Organization	Yes or No	Question 13 Comment
Response:		
Consolidated Edison Company of New York, Inc.	Yes	In R5, the SDT should better define the phrase 'where a transmission line is put at potential risk due to the constraint.' This is rather vague and could lead to inconsistent practices between utilities. Con Edison defines all undesirable species on the full width of the ROW as 'potential risks to the transmission line' regardless of height or location at the time of vegetation management. Interim corrective action should only be required when the potential risk is approaching the imminent threat classification.
Response:		
Orange and Rockland Utilities, Inc.	Yes	In R5, the SDT should better define the phrase 'where a transmission line is put at potential risk due to the constraint.' This is rather vague and could lead to inconsistent practices between utilities. ORU defines all undesirable species on the full width of the ROW as 'potential risks to the transmission line' regardless of height or location at the time of vegetation management. Interim corrective action should only be required when the potential risk is approaching the imminent threat classification.
Response:		
Florida Municipal Power Agency (FMPA) and Some Members	Yes	In the Applicability section, the use of the term “Other” should be changed to another term, such as Force Majeure, since its purpose is not to include scope into the standard, but exclude scope from the standard.R4 uses the term “responsible control center”, which seems inappropriate. Consider using the term “responsible operating entity”. The M4 is simply a restatement of R4 without an example of types of evidence, e.g., such as voice recording, operator logs, etc.R5, consider using a different term than “constrained”, which has other transmission related connotations. Possibly “limited” or “hindered”.FMPA disagrees with a 3 year retention schedule for all of the Requirements and Measures. R4 and M4 would seem to be supported by operator logs, voice recordings and such and three year retention for such evidence is inconsistent with other standards.
Response:		
ITC Holding	Yes	In the previous draft the VRF’s R6 and R7 were listed as Medium; and in the latest revision they are listed as High VRF’s, what is the reason for this change or is this just a mistake?”Temporarily” should be removed from the requirement (R5 pg.9) this will be an interpretation issue and doesn’t add to the requirement.
Response:		

Organization	Yes or No	Question 13 Comment
Northeast Power Coordinating Council	Yes	NPCC participating members recognize the hard work the drafting team has done and appreciate the efforts to address the issues presented. An issue seems to be a recurring theme with the advent of the MVCD. Some believe that the eventual adoption of this standard with MVCD will result in the reduction of current trimming cycles and clearance distances. Opinions have been expressed that this may result in increased vegetation contacts and trips. After reviewing some of the MVCD distances, for example 3.12 feet at sea level for 345kV, some expressed the opinion that this is much less than what typical trim practices are today, and may actually “lower” the bar for trimming practices, and effectively allow a TO to trim less and reduce the margin of clearance.Requirement R1 discusses encroachment. M1 bullet 1 states one way to violate encroachment would be:”Real-time observation of encroachment into the MVCD...”From a practical standpoint what is meant here? Who would determine this and how would it be done? The intent is certainly to avoid a sustained outage. However, if a TO was in the process of trimming after an active growing season, and noticed a slight encroachment while trimming, would it be considered a reportable violation? How would the RE measure compliance with avoiding something, with the absence of a sustained outage reported? A statement should be added to the “Definition of Terms Used in Standard” section to indicate how terms defined in the NERC Glossary and used in the standard are identified (for example capitalizing the first letters of the term or using italics or bold font). To avoid confusion when a term might be used at the beginning of a sentence, bolding or italicizing the term should be considered. The Guideline and Technical Basis section should be a separate document, and not part of the standard (mentioned previously in question 8). It should be included in the Technical Reference Document.Applicability 4.2.4--A fenced area of a switchyard, station or substation can have vegetation that could present a potential risk to facilities. What is the reason for this exclusion, and the exclusion in Applicability Section 5--Background paragraph 3 “...this Standard does not apply...to line sections inside an electric station boundary.”Referring to our previous responses to questions 1 and 2 for Requirements R1, R2, and R3, what rating is used? It is possible to operate above a facility’s normal rating for a prescribed time (for example a transmission line may be operated above its normal rating but below its LTE rating for up to 4 hours). Operating at emergency ratings should be considered. During emergencies transmission lines might be loaded to their emergency ratings, thus increasing the sag, thus increasing the likelihood of a vegetation caused trip if the required clearances don’t take into account the increased loading. Especially in an emergency loading scenario, operating into an avoidable potential risk is very undesirable. Referring to FAC-003 - Table 2 - Minimum Vegetation Clearance Distances (MVCD), for 345kV (line to line), 3.12 foot (assuming to ground) clearance is required at sea level. IEEE Std 516-2003 IEEE Guide for Maintenance Methods on Energized Power Lines dated July 29, 2003, Table 5 (p. 20), lists the MAID (minimum air insulation distance) for 345kV phase to phase equipment at altitudes below 900 meters (2953 feet) to be 2.88 meters (9.45 feet) phase to ground. It is understood that MAID is “The shortest distance in air between an energized electrical apparatus and/or a line worker’s body at different potential...”, but the clearance differences at the various voltage levels seem very significant. If a figure is referenced in a requirement (R3), it would be preferable to have that figure positioned within that requirement. If that is not possible, it should be explicitly stated where the figure can be found. Requirement R5--Legal actions and other events that prevent vegetation maintenance work be included in the Introduction Section 4.3.1. What does “interim corrective action” mean specifically? The requirement as written needs to be made clearer. Without the Rationale box it loses its meaning (refer to the question 3 response).Interim

Organization	Yes or No	Question 13 Comment
		Corrective Actions are explained on page 28 of the separate Technical Reference Document, with examples such as modifying the inspection interval, or limiting the loading on the line (effectively changing its rating) to minimize sag. “Interim corrective action” should be defined and added to the Glossary.Are voltages referred to in the Standard (Applicability Section) line to line or line to ground for ac systems? (345kV line to line is 199kV line to ground, below the 200kV threshold in the standard). Are the voltages also applicable to DC equipment?
Response:		
Xcel Energy	Yes	On page 6, in paragraph 5 ("Background"), we suggest enhancing the 3rd paragraph by inserting the words "Active Transmission Right-of-Way", as follows: "...addresses vegetation management in the Active Transmission Right-of-Way along applicable overhead lines..." This change emphasizes that this does not apply to areas outside of the Active Transmission Right-of-Way. Comments to Requirments and Measures Section (pages 7 -9)The term Minimum Vegetation Clearance Distance (MVCD) should be explicitly defined as a new "definition" rather than explained in a "rationale" box. Additionally, formalizing the definition would give weight to how "Table 2" is supposed to be used. As it is currently drafted, the requirements of the standard don't refer to Table 2 at all. (i.e., - our understanding is that the rationale boxes are for clarification and the requirements should be able to convey what is necessary on their own.)MVCD - while we understand this as an 'engineering term', the terminology is difficult to convey since land owners tend to question the need to do anything more than the "minimum". We recommend revising the term to "Critical Clearance Distance (CCD)". M1 & M2 should be revised to insert the concept of "verified knowledge" (that is used in R4). This is because M1 & M2 do not clarify whose real-time obseration it is referencing. As such, we recommend stating "Real time verified knowledge of encroachement into the MVCD..." instead of just the term "observation" to make it clear that a trained, knowledgeable individual is making this determination. Also, it may make sense to turn "verified knowledge" into a defined term since it will be used in M1, M2 and R4. If it is not made a defined term, then the meaning in M1 & M2 must be clarified in those sections (maybe a cross refefrence to as defined in R4 and on page 15 will work). However, we think it is best to make it a defined term.R5: Rationale box: consider enhancing the second sentence by adding the word "significant", to read "...avoid significant risk..."R5: Requirement & Measure: consider adding exception language when the constraint is known to be longer than "temporary". e.g. - stand offs can occur on right of ways that cross federal and tribal lands and the entity cannot force the federal government to do do something.R6: Xcel Energy still believes the requirement in R6 that mandates an annual inspection is too onerous and is at odds with the results-based approach of these revisions. Xcel Energy urges the retention of the provision in the existing standard that allows the Transmission Owner to set the frequency of inspection. In some areas of the country, annual inspections may not be adequate. Yet in other areas, a longer inspection frequency may be perfectly reasonable and practical. Our point is that inspection frequency should not be treated as if it were “one size fits all”. If treated this way, we feel this could pose a risk to reliability and is not likely to be cost-effective. The Transmission Owner should be allowed some flexibility. However, if the drafting team disagrees and determines that an annual inspection is to be mandated, Xcel Energy believes that an exception to the annual inspection is appropriate when a non-subjective advanced technology such as LIDAR is utilized to achieve

Organization	Yes or No	Question 13 Comment
		actual clearance distances. This places the Transmission Owner in a situation where it can rationally determine that the objectively measured distances result in a situation where an inspection need not be performed within the next year. It is suggested that R6 be revised to read as follows: Each Transmission Owner shall perform a Vegetation Inspection of all applicable transmission lines at least once per calendar year, unless the Transmission Owner, based on a non-subjective advanced technology, such as LIDAR, determines that a longer inspection period is appropriate.R7: Revise the requirement to eliminate the superfulous language at the end of the sentence that says "... to ensure no vegetation encoachments occur wihtin the MVCD", i.e., R7 would read as "Each Transmission Owner shall execute a flexible annual vegetation work plan."
Response:		
Independent Electricity System Operator	Yes	Our comments to this point have focussed exclusively on the proof-of-concept for using the results-based criteria for developing a reliability standard. We have one comment on the specifics of Requirement R7 and its Measure M7. The rationale for M7 states that a flexible annual vegetation work plan allows for work to be deferred into the following calendar year provided it does not have the potential to become an imminent threat. This will evidently require some kind of assessment in each case. Will entities be expected to document those assessments as evidence in support of its view that the associated vegetation did not have the potential to become an imminent threat, or would it be sufficient to look at the outcomes of these decisions to defer items in the work plan - i.e. there were no imminent threats and sustained outages? Finally, we applaud the drafting team for its efforts in developing this draft. The industry has often commented about overly prescriptive requirements and I believe this draft has focused on the “what” of the requirements and left the “how” up to the appropriate entities. In our view this draft, with its succinctly stated requirements, represents an important first step in the right direction. Thank you.
Response:		
Ameren	Yes	Page 9, M7 - what are the limits of flexibility in executing "a flexible annual vegetation work plan"?
Response:		
Duke Energy	Yes	Please review the VRF Guideline because we believe that the VRF’s for R6 and R7 should possibly be changed to “Medium” instead of “High”. They were “Medium” in the last draft of FAC-003-2.
Response:		
Westchester County Board of Legislators	Yes	Please see e-mail sent to sar@nerc.com. Thank you.

Organization	Yes or No	Question 13 Comment
Response:		
Progress Energy Carolinas	Yes	Progress Energy believes that the VRFs for R6 and R7 should be returned to “medium” since no singular “risk-based” requirement in a defense in depth strategy should be depended upon to eliminate/prevent risk to grid reliability. In a defense in depth strategy, no one specific “risk-based” or “competency” requirement should be “high” unless failure to complete that singular requirement will result in an immediate “high” risk to grid reliability (if that is the case, then the standard is not truly employing a defense in depth approach). Also, R6 and R7 (which have a zero tolerance) have no differentiation between grid impacting facilities (IROL) and facilities primary impacting local customer reliability (i.e., radial lines to load, etc).
Response:		
North Carolina EMC	Yes	R4: The requirement to notify the responsible control center of an imminent threat may potentially result in confusion at the control center if the transmission lines in question are not part of the control center's actively monitored grid. As an example, NCEMC has a few short radial 230kV lines that fall under the requirements of this standard, but these lines are not shown on the BA's control center system because they are downstream from a protective device located at a tap off networked transmission lines. A vegetation-related outage on these lines would not result in any of the transmission elements continuously monitored by the control center being outaged, and the operator receiving a call notifying the imminent threat may not have any familiarity with the line section being identified, since it is not on their system. If prompt action to respond to any imminent threat is the intended goal, why not consider making it a significant part of the mitigating factors of an actual outage.
Response:		
City of Tallahassee (TAL)	Yes	Recommend deleting the “to avoid a Sustained Outage” in R1 and R2. Has a violation occurred if a momentary (successful reclose) outage occurs but the TO did not “observe(s) vegetation within the” MVCD? While it may not have to be reported on the quarterly report, Table 1 for the Lower VSL seems to suggest a violation of the MVCD has occurred, even if it was not “observed” as “required” in the Guideline and Technical Basis.In the Guideline and Technical Basis, the final paragraph for R1 and R2, line 3 contains an extra word “...encroachment is not be a violation...”In the Guideline and Technical Basis, the third paragraph for R6, line 2/3 contains an extra word “...230kV transmission at least once line during the calendar year.”
Response:		
Cleco	Yes	Requirement 4:Recommend the SDT consider modifying to make it clear the requirement applies to threats within the right of way (ROW).Requirement 4.3.1:Recommend adding human activities to the list of causes. Logging activities

Organization	Yes or No	Question 13 Comment
		are listed but other human activities such as private property owner tree care operations are not.
Response:		
Exelon	Yes	See R6. Exelon prefers “annual” to “calendar” but notes the requirement runs counter to the results based approach and could be interpreted to be inconsistent with R7.The Rationale for R6 is ambiguous and without justification suggests shorter but not longer cycles are acceptable. If local factors can shorten a cycle, they could also increase it. The Rational is in conflict with the prescriptive nature of the requirement.
Response:		
NERC Staff (12 staff members)	Yes	Standard Development TimelineThe Development Steps Completed section of the standard is incomplete. This section should include the dates of previous postings. Draft 1 of revised standard was posted for stakeholder comment from 10/27/08 - 11/25/08. Draft 2 of revised standard was posted for stakeholder comment from 09/10/09 - 10/24/09.Definitions of Terms Used in StandardThe definition of Active Transmission Right-of-Way is ambiguous and subject to interpretation. This definition need to be revised to add clarity. It is unclear what “active transmission facilities” are. In the gray box, the SDT should explain what “active portions of corridors” are, and how that is different than the “land that is occupied by active transmission facilities.” The terminology should be consistent. The example should state whether the width is the portion that has been cleared or should be cleared and if it was not maintained and should have been. The SDT should explain the reference to the National Electrical Safety Code in the gray box, and how it differs from the IEEE clearances. In addition, the team should explain why the Table 2 clearances set forth in the standard itself are not referenced. The examples in the “inactive portion” suggest that there are active transmission facilities (see references to conductors and circuits). The SDT should provide the rationale for excluded them from vegetation management. While vegetation is permitted to exist at the corridor edge, the SDT should address why there is no obligation to maintain it. The revised definition of Vegetation Inspection does not seem necessary. It appears that the SDT is using the definition to set an expectation for enforcement by adding “which may be combined with a general line inspection.” If both vegetation and general line inspections are to occur concurrently, there should be minimum background requirements to perform such inspections. We recommend that the last portion of the draft definition be moved to the Application Guideline section so the definition of Vegetation Inspection should be “The systematic examination of vegetation conditions on an Active Transmission Line Right of Way.”The team should consider making Minimum Vegetation Clearance Distance a defined term.Effective DatesThe effective date for Ontario needs to be tied to the effective date in the U.S.With respect to the second exception, the team should provide the rationale behind the exception for the effective date for “existing transmission line operated at 200kV or higher that is newly acquired by an asset owner and was not previously subject to this standard”. All existing transmission lines operated at 200 kV or higher are currently subject to vegetation management. Please explain why a new owner would get an exception for this.Based on the wording in the Exceptions section, it appears that some lines in the US could be brought into this standard prior to regulatory approval. (i.e. Lines operated below 200kV, designated by the Planning

Organization	Yes or No	Question 13 Comment
		Coordinator as an element of an IROL or as a Major WECC transfer path, become subject to this standard 12 months after the date the Planning Coordinator or WECC initially designates the lines as being subject to this standard. An existing transmission line operated at 200kV or higher that is newly acquired by an asset owner and was not previously subject to this standard, becomes subject to this standard 12 months after the acquisition date of the line(s))ObjectiveThe purpose of this standard should not be limited to outages that lead to Cascading, but prevention of all vegetation related outagesApplicabilityThis standard should apply to Generation Owners.The term Facilities is defined to exclude those in a fenced area of a switchyard, station or substation. The SDT should provide the basis for the exclusion.Footnote 1 needs to be clarified. It is too cursory.The “Other” section should not be included in this section. It is the expectation that the Compliance Enforcement Authority will not expect the Transmission Owner to prevent tree contacts that the TO could not prevent. This might be better suited in the Application Guideline section.In the “Other” section, the SDT should provide rationale for why the standard is not intended to address “human errors”.The SDT might consider rewording the “Other” section as:”This Standard shall not apply in circumstances where a requirement of this Standard was not complied with due to Acts of God, flood, drought, earthquake, major storms, fire, hurricane, tornado, landslides, logging activities, animals severing trees, lightning, epidemic, strike, war, riot, civil disturbance, sabotage, vandalism, terrorism, wind shear, or fresh gales that restricts or prevents performance to comply with this Reliability Standard's requirements, so long as the non-compliance was not caused by the fault or negligence of the Transmission Owner.”The team should provide justification for the applicability criteria they have selected; specifically why a 200 kV cutoff was chosen.The team should provide justification for eliminating fall-ins from outside the ROW.BackgroundAs a general comment, the background section seems repetitive.The fourth paragraph of the background section notes that this standard is not intended to prevent customer outages due to tree contact with lower voltage distribution systems. It is clear from the applicability section that this pertains to 200 kV and higher, although the standard contemplates that some lower voltage facilities could be subject to the standard. The SDT should address whether this paragraph also address customer outages due to tree contacts with respect to 200 kV or higher facilities.Requirements R1 and R2:R1If an auditor were to assess compliance with R1, they would need to have the list of conductors that were associated with an IROL or a Transfer Path. This list should be identified in the list of evidence that must be retained.R1 & R2 In the Rationale box, the term “a proven transmission design method” is used. Please describe what this refers to, and whether these refer to the IEEE minimum clearances. The SDT should state what the method was and what changes, if any, were made to it.The SDT should address why the requirements only reference line conductors and not transmission facilities or transmission lines (the VSLs refer to transmission lines).The word “encroaching” should be replaced with another word/phrase that clearly defines the concept for compliance purposes. The word, “encroach” could be interpreted differently by different people (how close can vegetation grow before it enters the MVCD and is it a violation of R1/R2 - is it 2”, 2’, 10”, 10’?), whereas the word “enter” is explicit.Guidance is offered in the Guideline section of the standard that implies that all TOs should retain this evidence, yet the evidence is not identified anywhere in the Measures or evidence retention sections of the standard.We suggest adding the phrase, “of its” to clarify that the TO is only responsible for facilities it owns. “In addition, the Transmission Owner should maintain detailed records of the findings of its planned inspections. This documentation constitutes evidence that the Transmission Owner had no encroachments into the MVCD Table

Organization	Yes or No	Question 13 Comment
		distances."Immediately after the phrase MVCD, we suggest including the text "as specified in FAC-003-2 Transmission Vegetation Management Table 2 - Minimum Vegetation Clearance Distances (MVCD). Table 2 is not referenced in any of the requirements. If you require entities to use the MVCD as stated in Table 2, then this should be referenced in at least R1 and R2.M1 & M2Overall, it appears that these measures are asking for evidence of non-compliance. The initial item under M1 & M2 (shown below) should be rephrased with the addition of the words "verbal or written report of a," otherwise the measure doesn't seem as though it could be used objectively. In addition, the words Real-time should be removed, as they ad confusion to the issue."Verbal or written report of a observation of encroachment into the MVCD, or"The phrase "Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period" should be changed to a footnote that reads "Consider Multiple Sustained Outages on an individual line, if caused by the same vegetation, as one outage regardless of the actual number of outages due to the same piece of vegetation"Momentary outages due to vegetation are also a violation of R1. Momentary outages from tree contacts may not result in a sustained outage but are evidence of a tree within the MVCD. The requirement should not be limited to only sustained outages. Consider this scenario: An entity self-reports a violation of the standard. Does that mean that if there is no actual "real-time observation" or a "Sustained Outage" there is no violation? Who must do the observing? Please explain.Requirement R3 Consider this scenario: A Sustained Outage occurs on a location that was not considered and therefore was not part of the TO's TVMP. Would this result in a violation simply because the location was not considered when the entity developed a TVMP?Requirement R4 Each requirement should identify "who shall do what under what conditions, for what reliability outcome." R4 has no identified reliability outcome. What is the reason for making a prompt notification? Is it to give the real-time system operator information on which to develop and implement an action plan if there is an outage on the line with the imminent threat? Then that should be stated in the requirement. R4 contains explanatory information. The sentence "A vegetation imminent threat condition is one which is likely to cause a Sustained Outage at any moment" should be moved to the blue box.Please explain what "verified knowledge" means. The Rationale section does not really address this. While this is in the Guidelines and Technical Basis section, it defines it as "implies reliable confirmation." This should be clarified and put in the measures section."Imminent threat" should be defined so that it does not evolve into an enforcement issue."Notify the responsible control center" should be clarified so that it does not evolve into an enforcement issue.Application Guideline for R4 should contain provisions in the imminent threat procedure for notification of the land owner.M4 should provide examples of acceptable evidence.Requirement R5 This requirement does not include a reliability outcome. The requirement should be rewritten to include a reliability outcome.Requirement R6 The Rationale for R6 is that one year "seems to be reasonable." The SDT should address how this relates to the practice in place now, and whether it is consistent with current practice or is more or less than current practice. If inconsistent, the SDT should provide an explanation.The Rationale states the TOs should consider other factors that could warrant more frequent inspections. If so, the SDT should explain whether we are requiring them to do so if such factors exist.This requirement does not include a reliability outcome. The requirement should be rewritten to include a reliability outcome.Requirement R7 R7 is ambiguous; it is not clear how this could be enforced objectively. The rationale for the "flexible" plan indicates that the owner can delay work as long as it will not pose an "imminent threat." The SDT

Organization	Yes or No	Question 13 Comment
		should explain what the Compliance Enforcement Authority would look at to determine that the work that was delayed was not causing an “imminent threat.” The SDT should address whether it would ever be acceptable to delay work on a critical line (covered under R1).In Requirement R7, please explain what “execute a work plan” means. Did the SDT mean implement a work plan? As drafted, it could be read to just have one in place. The SDT should explain what “flexible” means. Does it mean there will never be a FAC-003 violation if you fail to implement the plan? The Rationale says the work can be deferred if it does not have the potential to become an imminent threat. Please explain. Corresponding clarification changes should be made to the VSLs for this requirement.Either M7 or the evidence retention for M7 needs to include the annual work plan. Without that the Compliance Enforcement Authority can’t determine if the plan was executed. The VSLs for R7 imply that the entire annual plan will be accomplished. . . not a “flexible” amount of the plan - the VSLs don’t line up with the use of the word “flexible.”According to the VSL Guidelines the VSLs should be stated in language that identifies the degree of noncompliance in language that identifies the amount that was noncompliant, rather than the amount that was compliant. VSLs for R6 and R7 are stated in terms of the % of the required performance that was compliant and should be rephrased. GuidelinesThe following guidance is offered in the Guideline section of the standard:Documentation or other evidence of the work performed typically consists of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, work inspection reports and walk-through reports.Documentation is required when the annual work plan is adjusted or not completely implemented as originally planned. The reasons for the deferrals or changes and the expected completion date of postponed work should be documented.This implies that all TOs should retain this evidence, yet the evidence is not identified in nearly this level of detain in the Measures section of the standard. In addition, no part of the requirement or measure is clear in indicating that documentation is required to support the need for a work plan adjustment. Evidence Retention The evidence retention periods specified don’t reflect the guidance in the SDT Guidelines. Should the evidence retention be the later of three years or three years from the last audit? The second paragraph should be stricken because it seems to contradict the first paragraph retention period.VSLsThe SDT should verify that the VSLs for Requirement 3 are properly calibrated.Administrative ProcedureThe Administrative Procedure does not require prompt reporting of sustained outages; rather it requires only a quarterly report. This appears to be less stringent than the current requirements as employed today.The SDT should explain what “blowing together” means, and how this is different from a tree that grows into a line.FootnotesFootnote 1 should be deleted or modified. It is only relevant in explaining the proposed modifications to the standard. In footnote 4 the word, “substantially” adds ambiguity.Guideline and Technical BasisIn the Guidelines and Technical Basis section, it states “Requirements 1 and 2 state if the TO observes vegetation within the distances prescribed in FAC-003 - Table 2 it is in violation of this Standard.” This is actually in the Measures 1 and 2 and not the requirements.General commentsThere seems to be a lot of information not captured in the Requirements but rather are in various other sections. The SDT should clearly delineate whether these other sections are considered part of the Standard or just informational.With the next posting of the standard, the drafting team should include the following four points for stakeholder review:1. Justification for selection of the applicable lines. 2. Table listing each FERC directive and stakeholder issue (from the Issues Database) associated with the standard and identification of how the

Organization	Yes or No	Question 13 Comment
		team addressed each of these3. Table listing each VRF and identification of how the proposed VRF meets both NERC criteria for setting VRFs and FERC's five Guidelines for approving VRFs4. Document identifying how the proposed VSLs meet both NERC criteria for setting VSLs and FERC's four Guidelines for approving VSLs.There is a significant concern with the use of the Gallet equations in this standard. This standard eliminates Clearances 1 and 2 from the previous version and replaces it with a single Minimum Vegetation Clearance Distance (MVCD) based on the Gallet equations. This approach reflects the most basic lowest common denominator and significantly lowers the bar versus the performance expected from the existing standard. Further, it would not appear that responsible entities would use the Gallet equations as the basis for the development of the vegetation management program. Additionally, whereas the multiple clearance zones provide an indicator of proactive vegetation management, the current proposal does not provide an equivalent demonstration of proactive performance. This approach appears inconsistent with Order 693 and the presentation of NERC standards to provide a defense in depth strategy, which is a fundamental outcome of the results-based standards process. Order 693 states in P24 that the "reliability mandate of Section 215 of the Federal Power Act....contemplates the prevention of incidents, acts, and events that would interfere with the reliable operation of the Bulk Power System." The SDT should consider adding more clarification to the draft standard and white paper describing the building blocks for determining how much vegetation management (trimming) needs to be performed based upon growth rate of vegetation and the time between trimmings to reflect a proactive approach.The SDT should consider the impact of moving the reporting requirement in the existing standard to the compliance section of the new standard. The team should consider the reporting of this activity on an exception basis within a pre-defined timeframe following the event. This approach would provide more timely awareness to the Regional Entity and NERC of an event than the quarterly reporting expectation, and provide opportunities for identification and implementation of mitigating strategies in a more timely manner. While this approach removes an administrative type requirement from the standard that is believed to provide a deterrent to responsible entities, the increased timeliness of reporting in an exception basis would provide greater benefit to the effort to maintain reliability.Transmission Line is a defined term. The SDT should consider using this term in place of "transmission line."The report identified in the administrative section of draft 3 of FAC-003 is really a "Periodic Data Submittal" used to assess compliance and does not belong in an administrative section of the standard - it belongs in the compliance section of the standard. "Periodic Data Submittals" is one of eight different compliance monitoring and enforcement processes that may be used to monitor and assess compliance. The eight processes are identified in the Uniform Compliance Monitoring and Enforcement Program of the North American Electric Reliability Corporation and should not be mixed in with other processes or procedures. Each standard must list the appropriate processes in the compliance section of the standard so that there is a clear understanding of the purpose of the data submittal.As drafted, FAC-003-2 applies only to Transmission Owners. It also should apply to Generator Owners. The SDT should explain whether the issues brought forward in the GO/TO Report been considered and are addressed as part of this revision.Please update the mapping document so that it compares the last version of the approved standard to the latest proposed version of the standard so that it is easy to compare the proposed standard to the standard that is in force now.

Organization	Yes or No	Question 13 Comment
Response:		
Utility Risk Management Corporation	Yes	Suggested Improvements to M1. and M2.The purpose of Requirements R1 and R2 is to require the prevention of vegetation encroachments within the MVCD. As made clear in the background and remaining FAC 003-2 requirements, the overarching intent of FAC 003-2 is to prevent sustained outages caused by vegetation that could lead to cascading. However, both M1 and M2 include real-time observations of encroachment into the MVCD as an automatic violation of R1 or R2, respectively (even though the violations may not result in penalty or fine). This is inconsistent with the "defense in depth" goal sought by the committee, as a real time observation using new technologies may in fact demonstrate that the Transmission Owner is in fact aggressively managing vegetation to meet the MVDC requirements and is discovering new encroachments and remediating them quickly and effectively and thereby is not in violation of the standard.Similar to imminent threats, remediation procedures should be permitted for encroachments as well and serve to make clear the observation is not automatically a violation. Classifying a real-time observation of an encroachment automatically as a violation of R1 or R2 penalizes a Transmission Owner for identifying vegetation threats, which are less severe than imminent threats. Under Requirement R4, the transmission owner is permitted to take appropriate actions to alleviate an imminent threat through short term corrective actions upon observation of any vegetation that is near to or is encroaching into the MVCD. (See FAC-003-2 Guideline and Technical Basis, Requirement R4). Considering the allowance for remedial action under Requirement R4 when facing a condition that is "likely to cause a Sustained Outage at any moment," it seems excessive to qualify a real-time observation of an encroachment as a violation of R1 or R2. We suggest a better approach is to modify M1 and M2 to allow for remedial action. Or, in the alternative, the standard should clarify that observations of encroachments using software-enabled technology, such as LIDAR coupled with work order management systems, do not constitute a "real time observation of an encroachment." First, by modifying M1 and M2 to allow for remedial action as suggested below will deal with the concern we raise:M1. Evidence of violation of Requirement R1 is limited to: o Real-time observation of encroachment into the MVCD which is not mediated in accordance with R4. o ... M2. Evidence of violation of Requirement R1 is limited to: o Real-time observation of encroachment into the MVCD which is not mediated in accordance with R4. o ... In the Alternative, "Real-Time Observation" Should be Clarified. As noted above, a real-time observation of an encroachment is evidence of a violation of Requirements R1 and R2. Observations in real time mean "an actual field observation or measurement of the conductor-to-vegetation distance and not a calculated determination of relevant positions." (See FAC-003-2 Guidelines and Technical Basis, Requirements R1 and R2) Given the current definition, it is not clear observations using software-enabled LiDAR would trigger violations and thereby would discourage the Standard's emphasis on preventing sustained outages or Cascading due to grow-ins. This may result in penalties for registered entities that are engaged in good faith activities to prevent sustained outages. The meaning of "real-time observation" should be clarified as to remove any adverse incentives for vegetation inspection and management. To implement this suggestion as an alternative to allowing remediation to prevent an observation from being an automatic violation, the definition could be reworded to state:"Real-time observation" means an actual field observation or measurement of the conductor-to-vegetation distance which is not performed under the regular Vegetation Inspection of Requirement R6 or annual vegetation work plans in accordance

Organization	Yes or No	Question 13 Comment
		with Requirement R7. Such observations do not include calculated determinations of relative vegetation positions. Conclusion:Adopting one or both of these proposed changes would help R1 and R2 measures more fully meet the goal of preventing overgrown vegetation and systemic failures triggered by flash over, as stated in the background section on page 6 of FAC-003-2. The current M1 and M2 use of real-time observations conflicts with the expectation that utilities engage in "defense in depth" measures. As the guidelines conclude regarding Requirements R1 and R2, the Transmission Owner is expected to have a cohesive vegetation management program for managing vegetation in such a manner as to maintain separation between conductors and vegetation. This is to function in conjunction with the imminent threat procedure to facilitate interim corrective action. "However, brief encroachments by falling vegetation are not considered to be a violation." Making the changes suggested above - coupled with the existing requirement that the utility mitigate an observation in accordance with the utility TVMP through a response schedule - thereby advance the goals of the standard and take away an impediment to aggressive defense in depth.
Response:		
SERC OC Standards Review Group	Yes	The requirements (R6 and R7) for inspections and the performance of work plans are part of a defense-in-depth approach and as such the TO is not depending on singular requirements to prevent sustained outages, therefore, the VRF for R6 and R7 should remain medium not high. We applaud the attempt to improve the readability and ultimate comprehension of reliability standards by changing to this new template. We have included some comments also made by the SERC Vegetation Management Subcommittee (VMS)."The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers."
Response:		
SERC Vegetation Management Sub-committee	Yes	The requirements (R6 and R7) for inspections and the performance of work plans are part of a defense-in-depth approach and as such the TO is not depending on singular requirements to prevent sustained outages, therefore, the VRF for R6 and R7 should remain medium not high.
Response:		
GCPD	Yes	The standard should include only R1, R2 and the Clearance Table. Everything else should be in guidelines as to how you might comply with the standard. If R3 thru R7 remain in the standard then it is virtually the same as it exists today, just put in a different order.
Response:		

Organization	Yes or No	Question 13 Comment
CenterPoint Energy	Yes	The term "Active Transmission Line Right-of-way" (ATLROW) is not defined in sufficient detail in the Definition of Terms Used in the Standard section to know how to apply it to the Requirements and Measures. The Technical Reference merely depicts the relative position of energized conductors, but it does not show a graphical determination of the limits of the ATLROW. The ATLROW is missing a definable and determinable width in its current definition within the Standard which makes it an arbitrary term and does not allow for a clear and measurable expected outcome of each requirement. In several sections, the Standard relies on the specific determination of the physical width of the ATLROW to determine applicability of the requirements. The Vegetation Inspection definition refers to “on” an ATLROW. The Background section refers to “outside” the ATLROW. Table 1 refers to “within” and “on” the ATLROW. M1 and M2 refer to “inside” the ATLROW. R3 and M3 refer to “on” the ATLROW. The Administrative Procedure refers to “inside and/or outside” and “within” the ATLROW. The Guideline and Technical Basis section refers to “on or near” the ATLROW and the “limited” ATLROW “width”. It also says that, “The Transmission Owner should, therefore, endeavor to maintain its ATLROW to the full extent of its legal rights at all times in all cases.” Since the Standard does not currently define how a Transmission Owner is to determine the specific boundaries of the ATLROW, it would appear that the Transmission Owner is to make that determination on a case by case basis at its discretion. Should that not be the intent, we recommend the definition for the ATLROW to be, “A strip or corridor of land or aerial space that is occupied by energized transmission conductors with its operational clearance limits defined by the Transmission Owner’s specific legal rights but in no case less confining than the MVCD applied to the movement of the conductors within their Rating and Rated Electrical Operating Conditions.” This definition contains sufficient detail to determine the physical limits of the ATLROW, and it allows for vegetation management to apply within the full extent of the legal rights of the Transmission Owner while requiring a minimum area for vegetation management in undefined ROW’s to ensure Sustained Outages are minimized.M1 contains a reference to “real-time observation of encroachment into the MVCD” but does not explain who is to make the observation and where it is to be documented. If this is to be done by the Transmission Owner, then perhaps it should be a Measurement under R6 and recorded under M6.The language in R6 refers to inspecting “transmission lines” and Table 1 for R6 refers to inspecting “ROW”. Both areas should use consistent terminology.M1 and M2 have the potential for double jeopardy when a Sustained Outage occurs because the Violation Severity Level has an entry for an MVCD encroachment (which causes the outage) and another sister entry for the type of Sustained Outage. Some additional clarity in the application of M1 and M2 is necessary.R5 should include the exception stated in the Rationale text box to add clarity to the Requirement. R5 should read, “Each Transmission Owner shall take interim corrective action when it is temporarily constrained from performing planned vegetation work, where a transmission line is put at potential risk due to a constraint, except where the risk is avoided by implementing an alternate work methodology.” In the Guideline and Technical Basis section for R1 and R2 (page 15), there is a reference to records of “planned inspections” and “evidence” for no encroachment into the MVCD. This reference should be moved to R6 where the inspections are required. If R6 is intended to provide evidence for M1, then that should be stated in R6.In the Guideline and Technical Basis section for R6, the reference to the VSL calculation units and the example units should be consistent-the example should use “line miles”, not just “miles”.Table 2 contains several “*” in the voltage column that are not defined.In the Technical Reference on page 21, the following sentence should be deleted, “If constraints cannot be

Organization	Yes or No	Question 13 Comment
		overcome and if design clearances are sufficient, an exception to the Transmission Owner's 10-foot guideline might be made." The Technical Reference should not provide examples of granting exceptions as they may be misinterpreted as an endorsement by NERC to increase the planting of trees near and under transmission lines without taking into account several other factors such as ROW access, changing design conditions, future line additions and rebuilds. The inclusion of modifications to the wire zone on page 24 regarding the wire-border zone model should be re-examined to be sure they are specific to an environmental conservancy requirement while allowing for construction and inspection access as needed.In the Technical Reference on page 22 under Planning and Implementation, delete the sentence, "While designed primarily with transmission systems in mind, t is also applicable to distribution projects." The Standard should not imply its applicability to distribution systems since it is intended only as a transmission standard.In the Technical Reference, the last sentence on page 26 starting with "Appropriate actions..." should be moved to R5 where it applies. In general, the proposed FAC-003-2 has gone FAR beyond what was contemplated by the Commission in FERC Order 693 and equates to a total re-writing of the Standard for no apparent reason. The Commission's determination dealt with the following areas: (1) applicability; (2) inspection cycles; and (3) minimum clearances on National Forest Service lands. For instance in Paragraph 729, the Commission states, "As proposed in the NOPR, the Commission approves Reliability Standard FAC-003-1 with no proposed modification on the issue of clearances. The Commission reaffirms its interpretation that FAC-003-1 requires sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions...." Rewriting the minimum clearances introduced a new set of confusing definitions, and further burdens the Transmission Owners with new documentation requirements with little if any benefit when compared to the Clearance 2 concept in the existing Standard.A preferred approach would have been to incorporate the following few items into the existing Standard: (1) the RC versus the RRO; (2) the designation of a specific inspection frequency; (3) the Gallet equation; and (4) the applicability to National Forest Service lands.
Response:		
Ad Hoc Group subteam formed to review draft standard	Yes	The wording in R7 is troublesome. We believe that the process for developing the annual work plan is imbedded in R3. As discussed in question 2, demonstrating capability to actually perform those actions necessary to ensure no vegetation encroachments occur within the MVCD is the primary concern. Deferring such work into the next calendar year appears contrary to this concern and neutralizes the defense-in-depth concept by diminishing the imminent threat requirement of R4 to a primary means of defense. While we don't want to incent vague annual work-plans, we also don't want to remove the imperative that the work must be done.
Response:		
Nebraska Public Power District	Yes	Under section 4.3.1 add in ice storms as one of the force majeure events. This type of event may impact many TOs and should be included.

Organization	Yes or No	Question 13 Comment
Response:		
Oncor Electric Delivery	Yes	Use of the Gallet equation to determine the minimum gap between vegetation and conductor to prevent sparkover seems to be appropriate. No utility should be managing to this distance but developing a distance beyond this would be arbitrary. This is a reliability standard not a worker safety or vegetation management practices standard. As Federal agencies and other entities are interpreting the Standard to limit normal vegetation management efforts, the FERC should develop and adopt an overarching memo allowing utilities to maintain vegetation under any agency jurisdiction as a utility manages vegetation along the entire right-of-way corridor.
Response:		
Western Area Power Administration - Upper Great Plains Region	Yes	WAPA - UGPR would like to see "ice storms" specifically mentioned in Section 4.3.1. Having additional clarification as to what is considered a "major storm" would also be helpful.
Response:		
Bonneville Power Administration	Yes	We believe the minimum vegetation distances are very granular and nearly un-measurable in real life. When a person considers the table to be a list of minimums it seems that the regulated entities, or land owners would want the distances to be as close to the wire as possible. We would not want a non-technical manager to believe that any small distance outside of the noted distances is ok.
Response:		
Omaha Public Power District	Yes	We have concern over establishing proof an outage is exempt due to fresh gale. A fresh gale, or even a localized thunderstorm, can easily produce wind gusts that exceed the lines rated capacity for blow out. If an outage occurs under these conditions, the standard provides an exemption under Section 4.3.1, but there is often no way to empirically prove conditions exceeded the lines normal operating conditions. How should a utility handle these situations?
Response:		
Southen Company	Yes	We have concern over establishing proof an outage is exempt due to fresh gale. A fresh gale, or even a localized thunderstorm, can easily produce wind gusts that exceed the lines rated capacity for blow out. If an outage occurs under these conditions, the standard provides an exemption under Section 4.3.1, but there is often no way to empirically prove conditions exceeded the lines normal operating conditions. How should a utility handle these

Organization	Yes or No	Question 13 Comment
		situations? Please note there is a typographical error in the third paragraph on page 15, "...encroachment violation is not be a violation..."We would like to thank the Standard Drafting Team for their hard work. The time and effort they have put into developing this standard is obvious.
Response:		
Dominion	Yes	While not related solely to this standard, we suggest that no future standard be effective until approval has been granted by the applicable regulatory authority. Having an effective date that differs from the mandatory date is causing confusion/chaos on the part of the applicable registered entity(ies). With the current process, it is possible to have a standard that is mandatory conflict with a superseding newer version (or a new standard that contains requirements meant to supersede those in the mandatory standard). Applicable entity(ies) may not be able to comply with both when this is true, and may not be able to take steps necessary to transition from mandatory requirement to superseding requirement without becoming non-compliant.
Response:		
Westchester County Board of Legislators		1. Bulk Electricity System NOPR – FERC recently issued a notice of proposed rulemaking to revise the definition of "bulk electric system" (BES) to include all transmission facilities with a rating of 100 kV or above. 130 FERC ¶ 61,204 (Mar. 18, 2010). If approved, such revision might significantly increase the amount of transmission facilities subject to standard FAC-003. In areas with dense residential and commercial development, this revision will exacerbate existing conflicts between homeowners, municipalities, affected transmission owners (TOs), and regulating agencies. As described in comments below, compliance with the existing or perceived requirements in FAC-003 has produced numerous conflict in areas of dense development and narrow rights-of-way between homeowners, TOs, and regulating agencies because of economic, environmental, and aesthetic impacts. If FERC adopts the proposed BES definition, then the FAC-003 standard (current 001 and draft 002) should be extensively reviewed by the drafting team to evaluate the amount of affected facilities and the need for standard revision to avoid as far as possible further conflicts. 2. "Background" Section 5 – The draft adds a new section titled "Background" (Section 5). The existing standard FAC-003-1 does not include a similar section. This narrative section appears to provide interpretation on the rationale for a vegetation management reliability standard and to clarify the standard applicability. This discussion may be more appropriate in the accompanying technical reference, which describes and clarifies standard FAC-003. While identifying overgrown vegetation as cause of major outages and operational problems, this section fails to state that many other causes can lead to Cascading events. Indeed, of the many NERC reliability standards, only one, FAC-003, concerns vegetation management. While the August 2003 blackout was initiated by a tree contact, there were numerous other factors that caused this power outage to spread to over a dozen states. Section 5 should therefore be revised to clarify that FAC-003 is only one of many factors that can lead to a large-scale grid failure.

Organization	Yes or No	Question 13 Comment
		3. Standard Applicability Across Land Uses – Standard FAC-003-1 and the proposed draft do not vary in applicability, even though the types of land uses within and adjacent to transmission facilities vary widely. Among certain land uses, such as dense residential development, this can lead to substantial conflict between the TO and adjacent landowners, especially concerning environmental, aesthetic, and economic impacts. The Westchester County Board of Legislators identified such problems in its recent resolution, available at http://meetings.westchesterlegislators.com/Citizens/FileOpen.aspx?Type=4&ID=2828&AgencyName=WestchesterCounty . Notwithstanding the reliability imperative expressed by Congress in enacting Section 1211 of the 2005 Energy Policy Act, the implementation of reliability standard FAC-003 has produced significant challenges for all parties in suburban areas. In particular, surburban area homeowners, often on small parcels, that abut or are near to transmission rights-of-way have experienced dramatic impacts upon their properties and property values when TOs exercise their "full extent of legal rights at all times and in all cases", as stated on page 18 of the draft. Therefore, the development of standard FAC-003 must consider this backdrop and select requirements and accompanying text that provide some balancing of electric reliabilty with environmental and economic impacts. As presently written, the draft does not acknowledge such balance. 4. Varying Conditions – Requirement R1.2.1 of Standard FAC-003-1 identifies numerous local conditions that should be considered in determining appropriate clearance distances. This balanced evaluation of factors should be retained in FAC-003-2. 5. Full Legal Rights – The draft encourages TOs to exercise full legal rights at all times and in all cases. This language is not included in present standard FAC-003-1. As noted above, electric reliabilty and TO compliance with FAC-003 must not preclude other important societal factors. The language encouraging full exercise of legal rights should be removed from the draft.
Response:		
KCPL	Yes	**Requirement 4:** Recommend the SDT consider modifying R4 to make it clear the requirement applies to that which is within the Right Of Way (ROW) for the transmission facility. Obviously, the Transmission Owner has no authority or control beyond the ROW. This is also an audit concern regarding "triggering" this requirement on a subjective evaluation of "imminent threat". How does a Registered Entity, Regional Entity or Auditor determine what constitutes an "imminent threat"? This will be a matter of opinion and makes this a difficult requirement regarding compliance when a difference of opinion arises. In addition, as proposed, this requirement does not address the need to take immediate corrective actions to mitigate an imminent threat. The previous FAC-003 Standard included taking action to remove the "imminent threat" which is not included in this proposed version 2. What was the intention of the SDT in this regard? Recommend the SDT

Organization	Yes or No	Question 13 Comment
		consider language to include taking action to remove the imminent threat. **<u>In the “Guideline and Technical Basis” section:</u>** 1. Under R6: believe the word “per” is missing in the first sentence of the third paragraph between “once (per) line”. 2. Under R7: concerned regarding the use of words such as “never”, “at all times”, and “in all cases” in the bulleted items with paragraph 6 in this section as a guiding document. This is the kind of material that is creeping into compliance audits and recommend softening this language. **<u>Violation Severity Levels</u>** 1. Do not agree with the zero tolerance for encroachments that do not result in a service interruption for R1 and R2. 2. Not notifying the Control Center should be a HIGH and not removing the imminent threat should be a SEVERE.
Response:		

Consideration of Comments on 3rd Draft of FAC-003-2 Transmission Vegetation Management — Part of Project 2007-07 Vegetation Management

The Vegetation Management Standard Drafting Team and the Standards Committee's Process Subcommittee thank all those who submitted comments on the 3rd Draft of FAC-003-2 Transmission Vegetation Management. The standard was posted for a 30-day public comment period from March 1, 2010 through March 31, 2010. Stakeholders were asked to provide feedback on the standard and its proposed format through a special Electronic Comment Form. There were 13 questions posed, and most of the questions were developed to collect stakeholder feedback on the proposed "results-based format" for the standard. There were 55 sets of comments, including comments from more than 100 different people from over 60 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

On January 14, 2010, the NERC Standards Committee endorsed the use of Project 2007-07 Vegetation Management as the prototype for the proof-of-concept for using the results-based criteria for developing a reliability standard. The results-based initiative is intended to focus the collective effort of NERC and industry participants on improving the clarity and quality of NERC reliability standards by developing performance, risk and competency-based requirements that accomplish a reliability objective through a defense-in-depth strategy, while eliminating documentation-driven requirements that do not have an impact on bulk power system reliability.

This report provides a copy of each of the questions that was posted for stakeholder comment with the third draft of FAC-003-2, a summary indicating how the drafting team or the Process Subcommittee used stakeholder comments submitted in response to that question, and the comments received. The comments may be viewed in their original format at the following site:

http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Ben Eng	New York Power Authority	NPCC	4
7.	Brian Evans-Mongeon	Utility Services	NPCC	8
8.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
9.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Michael R. Lombardi	Northeast Utilities	NPCC	1
12.	Randy MacDonald	New Brunswick System Operator	NPCC	2
13.	Greg Mason	Dynegy Generation	NPCC	5
14.	Bruce Metruck	New York Power Authority	NPCC	6
15.	Michael Schiavone	National Grid	NPCC	1
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
17.	Robert Pellegrini		The United Illuminating Company	NPCC						1			
2.	Group	Jim Case	SERC OC Standards Review Group	X		X							
	Additional Member		Additional Organization	Region						Segment Selection			
1.	Gerald Beckerle		Ameren	SERC						1, 3			
2.	Alvis Ianton		Southern Illinois Power Cooperative	SERC						1, 3, 5			
3.	Melinda Montgomery		Entergy	SERC						1, 3			
4.	Ken Parker		Entegra	SERC						5			
5.	Larry Rodriquez		Entegra	SERC						5			
6.	Gwen Frazier		Gulf Power	SERC						1, 3, 5			
7.	Stephen Mizelle		Southern	SERC						1, 3, 5			
8.	Brad Young		E.ON.US	SERC						1, 3, 5			
9.	John Troha		SERC	SERC						10			
3.	Group	Louis Slade	Dominion	X		X		X	X				
	Additional Member		Additional Organization	Region						Segment Selection			
1.	Jalal Babik		Electric Market Policy	SERC						6, 5			
2.	Mike Garton		Electric Market Policy	MRO						6, 5			
3.	John Loftis		NERC compliance	SERC						1, 3			
4.	Angela Park		NERC compliance	SERC						1, 3			
5.	Aaron Jonas		Forestry	SERC						1			
4.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee										X
	Additional Member		Additional Organization	Region						Segment Selection			
1.	Chuck Lawrence		American Transmission Company	MRO						1			
2.	Tom Webb		Wisconsin Public Service Company	MRO						3, 4, 5, 6			
3.	Terry Bilke		Midwest ISO Inc.	MRO						2			
4.	Jodi Jenson		Western Area Power Administration	MRO						1, 6			
5.	Ken Goldsmith		Alliant Energy	MRO						4			
6.	Dave Rudolph		Basin Electric Power Cooperative	MRO						1, 3, 5, 6			
7.	Eric Ruskamp		Lincoln Electric System	MRO						1, 3, 5, 6			
8.	Joseph Knight		Great River Energy	MRO						1, 3, 5, 6			

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Joe DePoorter		Madison Gas & Electric	MRO						3, 4, 5, 6			
10.	Scott Nickels		Rochester Public Utilties	MRO						4			
11.	Terry Harbour		MidAmerican Energy Company	MRO						1, 3, 5, 6			
5.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				
	Additional Member		**Additional Organization**	**Region**						**Segment Selection**			
1.	Chuck Sheppard		BPA Transmission Field Services	WECC						1			
2.	Don Swanson		BPA Transmission Line Maintenance	WECC						1			
6.	Group	Joe Spencer (SERC staff) and Jack Gardner (VMS chair)	SERC Vegetation Management Sub-committee										X
	Additional Member		**Additional Organization**	**Region**						**Segment Selection**			
1.	Randy Gann		Alabama Power Company	SERC									
2.	Gerald Beckerle		Ameren Services Company	SERC									
3.	Jeffrey Hackman		Ameren Services Company	SERC									
4.	John Neagle		Associated Electric Cooperative, Inc.	SERC									
5.	Billy George		Duke Energy Carolinas	SERC									
6.	Ron Adams		Duke Energy Carolinas	SERC									
7.	Robert Trimble		E.ON U.S. Services Inc. for LG&E & KU	SERC									
8.	Jim Case		Entergy	SERC									
9.	Ralph Hale		Entergy	SERC									
10.	Marc Tunstall		Fayetteville Public Works Commission	SERC									
11.	Reggie Wallace		Fayetteville Public Works Commission	SERC									
12.	Terry Wilson		PowerSouth Energy Cooperative	SERC									
13.	Jack Gardner		Progress Energy Carolinas	SERC									
14.	John Wolfmeyer		SERC Reliability Corporation	SERC									
15.	Jerry Lindler		South Carolina Electric & Gas Company	SERC									
16.	Richard Dearman		Tennessee Valley Authority	SERC									
7.	Group	Ben Li	IRC Standards Review Committee		X								
	Additional Member		**Additional Organization**	**Region**						**Segment Selection**			

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1. Bill Phillips			MISO	MRO						2			
2. James Castle			NYISO	NPCC						2			
3. Charles Yeung			SPP	SPP						2			
4. Matt Goldberg			ISO-NE	NPCC						2			
5. Mark Thompson			AESO	WECC						2			
6. Patrick Brown			PJM	RFC						2			
7. Steve Myers			ERCOT	ERCOT						2			
8.	Group	Richard Kafka	Pepco Holdings, Inc. - Affiliates	X		X		X	X				
Additional Member			**Additional Organization**	**Region**						**Segment Selection**			
1. Pat Byrne			Pepco Holdings, Inc	RFC						1			
2. Dave Paduda			Potojmac Electric Power Company	RFC						1			
3. Steve Benn			Delmarva Power & Light	RFC						1			
4. Olivia Watts			Atlantic City Electric	RFC						1			
5. Steve Genua			Pepco Holdings, Inc	RFC						1			
9.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				
Additional Member			**Additional Organization**	**Region**						**Segment Selection**			
1. Rebecca Spach			FE	RFC						1			
2. Katrina Schnobrich			FE	RFC						1			
3. Dave Folk			FE	RFC						1, 3, 4, 5, 6			
4. Doug Hohlbaugh			FE	RFC						1, 3, 4, 5, 6			
10.	Group	Carter B. Edge	Ad Hoc Group subteam formed to review draft standard										X
Additional Member			**Additional Organization**	**Region**						**Segment Selection**			
1. Peter Heidrich			FRCC	FRCC									
2. Pat Huntley			SERC	SERC									
3. Roman Carter			NERC	NA - Not Applicable									
4. Steve Ruekert			WECC	WECC									
5. Chris Hajovsky			RRI Energy	NA - Not Applicable									
11.	Group	Frank Gaffney	Florida Municipal Power Agency (FMPA) and Some	X		X	X	X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
			Members										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Byerle	New Smyrna Beach	FRCC	1, 3, 4
2.	Jim Howard	Lakeland Electric	FRCC	1, 3, 5
3.	Greg Woessner	Kissimmee Utilities Authority	FRCC	1, 3, 5
4.	Lynne Mila	Clewiston	FRCC	1, 3, 4
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1, 3, 4
6.	Cairo Venegas	Fort Pierce Utilities Authority	FRCC	1, 3, 4, 5

12.	Individual	Thomas Glock	Arizona Public Service Company			X		X	X				
13.	Individual	Chip Turner	Tampa Electric Company	X		X		X	X				
14.	Individual	Stephen Mizelle	Southen Company	X									
15.	Individual	Silvia Parada Mitchell	TO/TOP	X		X		X	X				
16.	Individual	John Buckley	Omaha Public Power District	X				X					
17.	Individual	Howard Gugel	NERC Staff (12 staff members)										
18.	Individual	Gary Cox	Tucson Electric Power Co.	X									
19.	Individual	Edward Bedder	Orange and Rockland Utilities, Inc.	X		X							
20.	Individual	Greg Lange	GCPD				X						
21.	Individual	Christopher M. Crane	Westchester County Board of Legislators									X	
22.	Individual	Robert Beadle	North Carolina EMC			X	X	X					
23.	Individual	Mary Hetz	Ameren	X									
24.	Individual	James W. Smith	ITC Holding	X									
25.	Individual	Alan Gale	City of Tallahassee (TAL)					X					
26.	Individual	Virginia Cook	JEA	X		X		X					
27.	Individual	Weston Davis	Central Maine Power, Iberdrola USA	X									
28.	Individual	Eric Senkowicz	FRCC Manager of Operations										X

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
29.	Individual	Samuel Stonerock	Southern California Edison Company	X		X		X	X				
30.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				
31.	Individual	Chris Scanlon	Exelon	X		X		X	X				
32.	Individual	Jody Nelson	Ga Transmission Corp	X									
33.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
34.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
35.	Individual	Laura Zotter	ERCOT ISO		X								X
36.	Individual	Gerald T. Paulson	Western Area Power Administration - Upper Great Plains Region	X									
37.	Individual	Louis C. Guidry	Cleco	X		X		X	X				
38.	Individual	Tom Hayes	East Kentucky Power Cooperative, Inc.	X		X		X					
39.	Individual	Jack Gardner	Progress Energy Carolinas	X		X		X	X				
40.	Individual	Kevin Howard	Western Area Power Administrtaion	X								X	
41.	Individual	James Sharpe	South Carolina Electric and Gas	X		X		X	X				
42.	Individual	George Czerniewski	Consolidated Edison Company of New York, Inc.	X									
43.	Individual	Michael Pakeltis	CenterPoint Energy	X									
44.	Individual	Darryl Curtis	Oncor Electric Delivery	X									
45.	Individual	Thad Ness	American Electric Power (AEP)	X		X		X	X				
46.	Individual	Dan Rochester	Independent Electricity System Operator		X								
47.	Individual	Richard Dearman	Tennessee Valley Authority	X		X		X					
48.	Individual	Jim Fulton	BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	X									
49.	Individual	Edward Davis	Entergy Services	X		X		X	X				
50.	Individual	Jason Shaver	American Transmission Company	X									

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
51.	Individual	David Rocchio	Utility Risk Management Corporation										
52.	Individual	Earl Burnside	PPL Electric Utilities Corporation (NCR00884)	X		X							
53.	Individual	Jianmei Chai	Consumers Energy			X	X	X					
54.	Individual	John Humphrey	Nebraska Public Power District	X		X		X					
55.	Individual	Christopher M. Crane	Westchester County Board of Legislators										
56.	Individual	Mike Gammon	KCPL										

1. **In response to comments received regarding potential for "double jeopardy" and to provide differentiation between transmission lines designated as having IROLs and Major WECC transfer paths from those that are not, the SDT consolidated requirements R4 though R8 found in the August 2009 draft of FAC-003-2 into two requirements in the latest draft of FAC-003-2 (new requirements R1 and R2). Do you agree? Please explain.**

Summary Consideration: There were 43 comment forms indicating agreement with the proposed Requirement R1 and R2 and 8 comment forms indicating disagreement.

The major comment issues covered:

- The differentiation of IROL/WECC Major Transfer Path and other lines subject to this standard is defensible in the context of VRF. While vegetation outages to lines covered in R2 are preventable and as such violations, the practical impact to the BES is no different than an outage caused by other factors
- WECC Transfer Path criteria should not be included in a national standard.

The VMSDT considerations for the major comment issues are:

- The new R1 and R2 requirements have eliminated the double jeopardy problem. NERC's Standards don't allow two VRF's for the same requirement so the SDT created two requirements with different VRF's.
- The VM SDT believes that WECC criteria for Major Transfer Paths is not applicable in other RE's and assumed this to be common knowledge.

Some minor comment issues are:

- Encroachment of the MVCD should not be a violation. A sustained outage should be the grounds for a violation.
- MVCD should be defined.
- Lines which cannot impact the BES, regardless of voltage, should be exempted from the standard

The VM SDT considerations for the minor issues are:

- The team has concluded encroachment into the MVCD or 'spark-over' distance is a clear indication of improper or negligent vegetation management and further that such encroachment creates an imminent threat condition.
- MVCD is defined in both the Requirement and the Rationale.

FERC has directed the ERO to develop a methodology or test to designate "operationally significant" facilities in the March 18, 2010 Order 733. The test is intended for application in PRC-023-1; however it can be extended for FAC-003-2 use.

Organization	Yes or No	Question 1 Comment
Westchester County Board of Legislators		Do not have enough knowledge on this to provide response.

Organization	Yes or No	Question 1 Comment
Nebraska Public Power District	No	Although it does provide some flexibility to the TO, it will be difficult to determine an encroachment into the MVCD. It would easier to implement if R1 and R2 were only applicable when there was an outage on the transmission system.
Dominion	No	Dominion does not agree with the inclusion of facilities that WECC designates as 'major transfer paths' in a continent-wide standard. We suggest that, if the SDT wishes to include such reference and these facilities are meant to be treated or synonymous with either IROL or SOL, that the SDT add a proposal to adopt and define a suitable term for inclusion into the Glossary of Terms
Cleco	No	Encroachment into the MCVD should require the owner to take immediate corrective action to mitigate the threat. Such an encroachment should not be reportable as a violation. Owners may be hesitant to communicate possible vegetation threat conditions to the TOP or proper authority if they believe it will be reported as a violation. We recommend the SDT consider modifying the measure for R1 and R2 to be applicable only in the interruption of the transmission facility.
NERC Staff (12 staff members)	No	NERC Staff does not see a need to have two requirements (R1 and R2) which differentiation between transmission lines designated as having IROLs and Major WECC transfer paths from those that are not with two different Violation Risk Factors. The standard as drafted applies to all 200kv and above lines. The Violation Risk Factor for all 200 kV and above lines should be "High". R2 should be deleted and R1 should be rewritten to be:R1. The Transmission Owner shall prevent vegetation from encroaching within the Minimum Vegetation Clearance Distance (MVCD) of applicable Transmission line conductors to avoid a Sustained Outage.
Xcel Energy	No	Requirements 1 & 2 are identical except for their applicability (R1 for IROL elements and elements in the WECC Transfer Paths; R2 for all other lines =>200 KV). It is not readily apparent as to why there is a need to distinguish between the two. Referencing the Table 2 "VRF" and "VSL" matrix indicates that R1 has a "High" VRF and R2 has a "Medium" VRF. If this is the only reason, then consider adding, at a minimum, a "Rationale" box explaining that reasoning.Also, the definition of MVCD needs to be a defined term or included in R 1 & 2, e.g., "Minimum Vegetation Clearance Distance is the calculated minimum distanced stated in feet (meters) to prevent spark-over between conductors and vegetation for various altitudes and operating voltages as set forth in Table 2." See comments to # 7 and # 13.
Arizona Public Service Company	No	This is a reliability standard for 230 kV and above and those lower voltages designated by the RRO. An outage is an outage and the utility should be held accountable no matter if they are or are not designated.
SERC OC Standards Review	No	While we agree with the development of a second requirement to provide for the distinction between line segments that are critical for reliability, in R1, a regional distinction should not be embedded in a national

Organization	Yes or No	Question 1 Comment
Group		standard. We also strongly disagree that perfect compliance with R2, as stated, would improve reliability. If a line is operated to avoid projected post contingent overloads, then the tripping thereof due to any cause has no effect on BES reliability. A more prudent approach for the lines covered by R2 could be the requirement to achieve 3 sigma or 4 sigma performance over a year's time. Requirement 2, as stated, is not cost effective, and may produce an unjust and unreasonable outcome to rate payers.While this draft clarifies (from version FAC-003-1) that sustained outages are compliance violations and eliminates the "double jeopardy" which was errantly introduced in the last draft of FAC-003-2 (when sustained outages were clearly defined as compliance violations), we suggest that the team adjust R2 as previously mentioned. This draft provides a mechanism to address the difference in outages that have impact to grid reliability from those that have an impact only to local lines and associated customer reliability. The use of observed MVCD as a violation and in the violation severity level matrix: o drives the right behaviors for improving reliability (by proactively identifying and removing vegetation before it can become an imminent threat or cause an outage) o eliminates the need to perform detail engineering/surveying/theoretical calculations before cutting vegetation, o formalizes the informal interpretations that have resulted from FAC-003-1 enforcement and o allows the vegetation field operations to focus on facts and remain practical rather than theoretical.
KCPL	No	The measures for R1 and R2 are zero tolerance for encroachments into the MVCD that did not result in a "contact" with the transmission facility. Considering the substantial number of miles of transmission involved, the complexities in anticipation of vegetation growth with numerous growth variables, vegetation management limitations imposed by other regulations or requirements, and unexpected transmission events that require substantial efforts regarding physical restoration, it is not reasonable or practical for the measures here to include encroachments that do not result in an interruption of transmission service. Recommend the SDT consider modifying the measures for R1 and R2 to be applicable only in the interruption of a transmission facility.
American Transmission Company	Yes	
Bonneville Power Administration	Yes	
Central Maine Power, Iberdrola USA	Yes	
City of Tallahassee (TAL)	Yes	
Consumers Energy	Yes	

Organization	Yes or No	Question 1 Comment
Duke Energy	Yes	
Florida Municipal Power Agency (FMPA) and Some Members	Yes	
FRCC Manager of Operations	Yes	
Ga Transmission Corp	Yes	
GCPD	Yes	
ITC Holding	Yes	
Manitoba Hydro	Yes	
Omaha Public Power District	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	
Southen Company	Yes	
TO/TOP	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	
MRO's NERC Standards Review Subcommittee	Yes	1. NSRS agrees with the revisions that the drafting team has made and agrees with the combining of four requirements into two. NSRS prefers the MVCD methodology to the minimum clearance distance

Organization	Yes or No	Question 1 Comment
		methodology due to the fact that there is only one measurement to contend with versus two.2. If a company has a line with a standing IROL could they be found in violation of both the requirements R1 and R2? If so, the NSRS recommends combining R1 and R2.3. Please clarify the need for R1 and R2. Why were lines with IROL separated out from lines without IROLs?
American Electric Power (AEP)	Yes	American Electric Power agrees with this change.
IRC Standards Review Committee	Yes	Because real-time observation in Measurement 1 would require an actual measurement for comparison to Table 2 to be defendable as a violation, the SRC suggests replacing observation with measurement. The SRC would suggest deleting the phrase "to avoid a sustained outage" as that phrase does not add any clarity to either of the two requirements. There do not seem to be any encroachments that the SDT will allow. If there are encroachments that are considered allowable, who is responsible for making that consideration? And what would be considered a "sustained" outage?Minimum Vegetation Clearance Distance (MVCD) is a capitalized term used in Requirements 1, 2 and 7 but is not defined in the NERC Glossary of Terms Used in Reliability Standards nor is a definition proposed in this standards action. Either a definition should be proposed or the capitalization should be removed.
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	BGE agrees with the consolidation of R4 through R8 into two requirements in the FAC-003-2 draft.
Ameren	Yes	Creating two specific requirements removes the potential for double jeopardy.
Southern California Edison Company	Yes	SCE agrees that the consolidation of Requirements R4-R* resolves the "double jeopardy" issue.
Tampa Electric Company	Yes	The change in the draft serves to consolidate, clarify and remove the “double jeopardy” as stated above. This is an improvement in the standard.
CenterPoint Energy	Yes	The differentiation in the Violation Risk Factor for R1 versus R2 seems appropriate.
Consolidated Edison Company of New York, Inc.	Yes	The elements that comprise IROLs must be clearly communicated to each Transmission Owner and must be consistent across North America.
Orange and Rockland Utilities, Inc.	Yes	The elements that comprise IROLs must be clearly communicated to each Transmission Owner and must be consistent across North America.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	Yes	The most recent draft of the standard consolidated R4-R8 results in clearer requirements that meet the results based criteria and addresses the “double jeopardy” issue. However, there is concern with the differentiation of lines designated as having IROLs and Major WECC transfer paths from those that are not, as is proposed in the Applicability section 4.2 and subsequently in requirements R1 and R2. As stated in the background section: “This Standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this Standard is not written to address such isolated situations which have little impact on the overall Bulk Electric System.” It must be recognized that in some systems, outages on lines operated at voltages greater than 69 kV, 200 kV for example, have localized impact only and do not lead to Cascading. Concurring with the background, a line should be subject to this standard only if a vegetation related outage “could lead to Cascading”, or could have a “significant impact” on the system. It does not depend on whether it is an IROL line or not.A performance based methodology is used in NPCC to determine if an outage on a line can cause a “significant impact” on the system. The lines identified by this methodology are not identified according to their voltages, but rather by their impact on the system, regardless of the voltage.The introduction of “two” subcategories of BES - an IROL and a non-IROL - appears to just differentiate between high VRF and medium VRF. Furthermore, in the Applicability section, the IROL “variable” is mentioned only for lines operated below 200 kV. What about lines operated at or above 200 kV lines? Why not have a single Application item stating: overhead transmission lines operated at any voltage whose outages have a significant impact on the system? A Table could define what is considered “significant”.There are standards for vegetation management on the distribution system, and there are standards for higher voltage systems. This standard should focus on lines with high impact on the system when a vegetation outage occurs.Utilities will not let the vegetation encroach on other lines, but an importance will be given to vegetation management on “critical” lines for the reliability of the whole system. On other lines, if an outage occurs, it will have localized impact.A “Results-Based Reliability Standard” should first focus on the “critical” lines.If it is the intent of NERC or the industry to ensure that a vegetation outage causes no more than a fixed level of load loss, it should say so in a requirement.If the IROL “variable” is retained, identification of the transmission elements that comprise IROLs must be officially communicated to the Transmission Owners. This must be done either through a requirement in this, or another standard.
Progress Energy Carolinas	Yes	The previous version (FAC-003-1) was not developed with individual outages listed as a requirement or a violation. The previous drafts of version 2 (FAC-003-2) have improved on FAC-003-1 by defining sustained outages from within the Right-of-Way as violations. However, the recent drafts of FAC-003-2 also introduced a potential for ‘double jeopardy’ when clarifying that sustained outages and MVCD encroachments were (‘binary’) requirements/violations. This latest draft clarifies the expected performance into two concise requirements that provide for differentiation in severity levels and risk factors, eliminating the unintended

Organization	Yes or No	Question 1 Comment
		‘double jeopardy’. The inclusion of the use of observed MVCD as a violation of R1/R2 and in the violation severity level matrix drives the right behaviors for improving reliability (by proactively identifying and removing vegetation before it can become an imminent threat or cause an outage) , eliminates the need to perform detail engineering/surveying/theoretical calculations before cutting vegetation, formalizes the informal interpretations that have resulted from FAC-003-1 and allows the vegetation field operations to focus on facts (and remain practical rather than theoretical). Progress Energy believes that the R1 and R2 changes to this draft are a significant improvement over FAC-003-1. This version draft: clarifies real-time MVCD and sustained outages as a requirement; provides for differentiation between grid impacting outage events and outage events to lines primarily associated with customer reliability; introduces a performance barrier/defense that is fact based - eliminating the need to determine compliance through theoretical calculations that rely on design assumptions (e.g., mechanical behavior of aged conductor), prior design criteria/code versions (i.e., code clearances in effect at time of design) and detail site measurements (e.g., “survey” quality measurements and local environmental conditions at time of measurement/event).
JEA	Yes	The simplification and clarification improves the ability of Registered Entities to comply thereby enhancing reliability.
Independent Electricity System Operator	Yes	This change addresses the perceived “double jeopardy” risk.
Oncor Electric Delivery	Yes	This does not reduce the Standards effectiveness on the cascading issue or discount any outage on applicable lines subject to this Standard in the electric Transmission system.
East Kentucky Power Cooperative, Inc.	Yes	This draft adequately addresses the "double jepoardy" issue. The use of the Minimum Vegetation Clearance Distances simplifies recommended maintenance process for field personnel and eliminates the need to perform costly and time consuming engineering studies prior to trimming or removing vegetation.
SERC Vegetation Management Sub-committee	Yes	This draft clarifies (from version FAC-003-1) that sustained outages are compliance violations and eliminates the “double jeopardy” which was errantly introduced in the last draft of FAC-003-2 (when sustained outages were clearly defined as compliance violations). This draft provides a mechanism to address the difference in outages that have impact to grid reliability from those that have an impact only to local lines and associated customer reliability. The use of observed MVCD as a violation and in the violation severity level matrix: o drives the right behaviors for improving reliability (by proactively identifying and removing vegetation before it can become an imminent threat or cause an outage) o eliminates the need to perform detail engineering/surveying/theoretical calculations before cutting vegetation, o formalizes the informal interpretations that have resulted from FAC-003-1 enforcement and o allows the vegetation field operations to focus on facts and remain practical rather than theoretical.

Organization	Yes or No	Question 1 Comment
Western Area Power Administrtaion	Yes	This is a very efficient and logical consolidation of requirements.
Western Area Power Administration - Upper Great Plains Region	Yes	This is not a critical issue for the WAPA - UGPR.
Tennessee Valley Authority	Yes	This method effectively recognizes the difference in reliabilty risks among various lines based on their value to the transmission grid.
Entergy Services	Yes	We agree that R1 and R2 are beneficial, but believe that they should be explained in greater detail for much greater clarity to reflect their intent. Our understanding is that R1 applies to ALL IROL's and ALL Major WECC Transfer Path lines, regardless of voltage, and R2 is centered around ALL lines operated at voltages 200 kV and above but are not classified as IROL/WECC lines. Our understanding of the term "applicable line conductor" in R2 refers back to the facilities defined in Facilities - Section 4.2 and as modified by the phrase in R2: "which are not elements of an IROL and are not a Major WECC transfer path, (operating within Rating and Rated Electrical Operating Conditions)". However the appropriateness of our assumed reference back to Section 4.2 and the modification contained in R2 is not clear. It also is not clear that the term "applicable line conductor" in R2 is the same as "applicable line conductor" in R6. We suggest the term "applicable line conductor" be specifically defined as that term is intended to be applied in R2, and the term "applicable line conductor" be defined as that term is intended to be applied in R6.
FirstEnergy	Yes	We agree that the new R1 and R2 alleviate the potential double jeopardy issue as well as differentiate the high and medium risk factor transmission lines. However, we offer the following comments and suggestions for improvement:It is not clear how the Transmission Owner (TO) will determine which lines are associated with IROLs. Upon reviewing standard FAC-014 Req. R5, which requires the communication of SOLs and IROLs, the required communication of IROLs to the TO is not specified. There needs to be a tie between this standard and the FAC-014 standard, which will require a revision to FAC-014. Unfortunately, this issue will create a gap if FAC-014 is not revised and submitted to FERC in parallel with the submittal of FAC-003-2 to FERC. This may require immediate action such as an urgent action SAR or other appropriate actions.If our suggestion to revise FAC-014 is not possible at the present time, then we suggest an alternative course of action to include language in R1 of FAC-003 to aid the TO in obtaining the information regarding lines associated with IROLs. We propose adding the following sentence to R1: "The Transmission Owner can request information regarding transmission lines associated with an IROL from its Planning Coordinator."
Ad Hoc Group subteam formed to	Yes	We understand the differentiation to be around the intent that those transmission lines designated as having IROLs and Major WECC transfer paths pose a more significant threat to the reliability of the BES and that

Organization	Yes or No	Question 1 Comment
review draft standard		encroachment of the MVCD in these cases are relatively more significant. We suggest that this be clarified in the rationale.

2. **The results-based reliability standard criteria focus on striving to achieve a portfolio of performance-based, risk-based, and competency-based mandatory reliability requirements that provide an effective defense-in-depth strategy for achieving an adequate level of reliability of the bulk power system in lieu of prescriptive requirements. Consequently, the SDT revised R1 and its subparts found in the August 2009 draft of FAC-003-2 in favor of the text in the latest draft of FAC-003-2 (new requirement R3). Do you agree? Please explain.**

Summary Consideration: There were 41 comment forms that indicated agreement with revising Requirement R1 found in the August 2009 draft of FAC-003-2 in favor of the text in the latest draft (new requirement R3) and 12 forms indicating disagreement.

The major comment issues covered:

- Several respondents felt R3 lacked clarity and needed more definition. However there were a large number of commenters who specifically pointed out an appreciation for the requirement being less prescriptive and allowing the Transmission Owner flexibility in developing its program.
- Several respondents felt encroachment of the MVCD should not be a violation.
- There were several concerns raised with citing the Rating and Rated Conditions to describe the conditions the Transmission Owner should use to develop its clearances and avoid encroaching into the MVCD.
- The term “Bulk Power System” should not be used in this Requirement.

The VM SDT considerations for the major comment issues are:

- Due to the large number of respondents who expressed a positive opinion of eliminating prescriptive items in R3 using the Results-based approach the SDT felt R3 is appropriate as written.
- The team has concluded encroachment into the MVCD or ‘spark-over’ distance is a clear indication of improper or negligent vegetation management and further that such encroachment creates an imminent threat condition.
- The team has further described Rating and Rated Conditions in the Guideline and Technical Basis Section under Requirement R3.
- This term “Bulk Power System” has been removed from every instance in the Standard.

Some minor comment issues are:

- Make Standard dependant on R1 and R2 only. Remove all other requirements.
- Add NESC clearance requirements to R3.

The VMS SDT considerations for the minor comment issues are:

- One of the tenets of the Results-based framework is a set of building blocks which support each other. While R1 and R2 are the ultimate test of reliability they are an insufficient number of building blocks for an Results-based Standard.
- While adding NESC clearance requirements to R3 may clarify what is needed to develop the document, the SDT felt that Rating and Rated Conditions adequately cover this.

Organization	Yes or No	Question 2 Comment
Tampa Electric Company	No	A more in-depth technical review of this requirement is required. Our response is predicated upon the following quote from the draft standard; “...considering all possible locations the conductor may occupy assuming operation within Rating and Rated Electrical Operating Conditions.”
NERC Staff (12 staff members)	No	As written, R3 does not provide enough clarity as to what should be included in a documented transmission vegetation management program. R3 should be expanded to include what should be included in the transmission plan. Such as:R3. Each Transmission Owner shall have a documented transmission vegetation management program that describes how it conducts work on its Active Transmission Line Rights of Way to avoid Sustained Outages due to vegetation, considering all possible locations the conductor may occupy assuming operation within Rating and Rated Electrical Operating Conditions. The transmission vegetation management program shall:3.1 Specify the methodologies that the Transmission Owner uses to control vegetation.[1] 3.2 Specify a Vegetation Inspection frequency of at least once per calendar year that takes into account local[2] and environmental factors. 3.3 Require an annual work plan that identifies the applicable lines to be maintained and associated work to be performed during the year. It shall be flexible to adjust to changing conditions and to findings from Vegetation Inspections. Adjustments to the plan within the year are permissible. The plan shall take into consideration permitting and scheduling requirements from landowners or regulatory authorities. It shall support the objectives of the transmission vegetation management program and utilize the methodologies outlined in the transmission vegetation management program. 3.4 Require a process or procedure for response to imminent threats[3] of a vegetation-related Sustained Outage. The process or procedure shall specify actions which shall include immediate communication of the threat to the Transmission Operator or proper operating authority. The process or procedure shall specify what conditions warrant a response.3.5 Specify an interim corrective action process for use when the Transmission Owner is constrained from performing vegetation maintenance as planned. 3.6 Specify the maintenance approach used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that Table 1 clearances in Attachment 1 are never violated. The maintenance approach shall consider the sag and sway of the conductor throughout its operating range under rated conditions.[1] ANSI A300, Tree Care Operations - Tree, Shrub, and Other Woody Plant Maintenance - Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.[2] Local factors include treatment cycle, extent and type of treatment, and their relationship to the normal growth rate.[3] The term “imminent threat” refers to a vegetation condition which is placing the transmission line at a significant risk of a Sustained Outage. Refer to Technical Reference for examples of imminent threat procedures and conditions for implementation.
Consumers Energy	No	Consumers Energy strongly disagrees with the MVCD as presented in this version of the standard. These distances do not provide an adequate safeguard to prevent outages since the conductor position relative to the vegetation is sensitive to electric load and wind at any particular moment while vegetation height is not. Measurements M1 and M2 require real-time observation of a violation of MVCD to be reportable. As

Organization	Yes or No	Question 2 Comment
		presented, vegetation growing beneath the conductor with a clearance of MVCD + 1 foot is not reportable. However, this same conductor may sag due to load increase or move due to wind displacement within hours of the real-time observation. If great enough, the sag or displacement may move the conductor in contact with the vegetation resulting in an outage just hours after being deemed compliant.At a minimum the MVCD should be designed to provide the Gallet clearance distance at maximum sag or wind displacement (whichever is greater) at all times. No matter when the line is cleared of vegetation or inspected for vegetative conditions, if the enhanced MVCD is being met an outage cannot occur until further vegetative growth occurs. Furthermore, for line clearing operations, tree crews do not and cannot determine in the field the maximum potential sag or wind displacement to know how much vegetation to clear. They require much clearer instructions with a set amount of clearing distance to obtain at the time of work. This distance must account for maximum sag, wind displacement and the Gallet distance at a minimum.
Cleco	No	Encroachment into the MCVD should require the owner to take immediate corrective action to mitigate the threat. Such an encroachment should not be reportable as a violation. Owners may be hesitant to communicate possible vegetation threat conditions to the TOP or proper authority if they believe it will be reported as a violation. We recommend the SDT consider modifying the measure for R1 and R2 to be applicable only in the interruption of the transmission facility.
GCPD	No	Grant believes that R1 and R2 should be the entire standard and the rest of the requirements should be in guidelines and supplementary materials to assist in meeting the two results based requirements. We understand that some risk-based and competency based requirements are necessary for some standards. Not this one. No grow-in caused outages is the objective. Requiring a specific plan does not show competency, it just shows you have a plan. Feels very much like the existing standards. "Show us your Documentation".
Northeast Power Coordinating Council	No	R3 specifies "...considering all possible locations the conductor may occupy assuming operation within Rating and Rated Electrical Operating Conditions." Although both "Rating" and "Rated Electrical Operating Conditions" appear in the NERC Glossary, inspection of these definitions shows that they are very vague, and "Rated Electrical Operating Conditions" uses the word "reasonably", a term FERC has previously indicated as being unacceptable. From a practical standpoint this seems to allow too much latitude to an entity to do the least amount of trimming and not consider the extra sag and swing caused by some of the more extreme operating conditions that "may" occur, such as loading to an STE or DAL limit during a higher velocity wind than normal, coupled with a higher ambient temperature. An entity could potentially claim that vegetation was trimmed to normal load levels, normal facility loading sag, and minimum velocity wind speed swings, and be within the tolerance of the standard as we interpret it. The Drafting Team should clarify what the expectation is with regard to line loading, sag, and swing due to wind speed and the types of operating conditions it deems to be justified to create a more exact requirement.

Organization	Yes or No	Question 2 Comment
Nebraska Public Power District	No	same concern as item 1.
Central Maine Power, Iberdrola USA	No	The TVMP must include clearances bewteen trees and conductors at time of vegetation management work.Suggest that the TVMP require the use of qualified personnel to manage this program.
Arizona Public Service Company	No	This standard lacks accountability and transparency. This is a reliability standard and the industry is to prevent outages within the active ROW. It doesn't matter if the vegetation grows-in, blows-in or falls into the conductor these are all outages. One is no less of an outage than the other one. They should be treated equally and the utility should be held accountable for lack of maintaining the transmission system.
FirstEnergy	No	We agree that the previous R1 was too prescriptive and are in favor of the new Requirement R3. However, we do not agree with all the wording of R3 as well as the Rationale box for R3. 1. Requirement R3 - The phrase "considering all possible locations the conductor may occupy assuming operation within Rating and Rated Electrical Operating Conditions" is confusing. We like the wording from the previous (Draft 2) of FAC-003-2 and suggest the following rewording of this phrase: "considering all possible locations the conductor may occupy throughout its operating range under all rated conditions."2. Rationale box for Req. R3 - We suggest removing the first sentence in the Rationale box for R3. The need to provide a basis on the intent and competency of the TO in maintaining vegetation is not explicitly stated in the requirement. Also, we are not sure what is meant by "competency". If it is referring to minimum required competencies for personnel performing vegetation management, that is outside the scope of this standard.
Ameren	Yes	
Bonneville Power Administration	Yes	
City of Tallahassee (TAL)	Yes	
Consolidated Edison Company of New York, Inc.	Yes	
Duke Energy	Yes	
Entergy Services	Yes	
Exelon	Yes	

Organization	Yes or No	Question 2 Comment
FRCC Manager of Operations	Yes	
Ga Transmission Corp	Yes	
Manitoba Hydro	Yes	
North Carolina EMC	Yes	
Omaha Public Power District	Yes	
Orange and Rockland Utilities, Inc.	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	
Tennessee Valley Authority	Yes	
TO/TOP	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	
Xcel Energy	Yes	
MRO's NERC Standards Review Subcommittee	Yes	1. NSRS agrees with the revisions to R3. With regard to operations within Ratings and Rated Conditions, are operations after a contingency considered to be within Ratings and Rated Conditions?2. Could wording be added to R3 to specify rated conditions include National Electric Safety Code conditions or assumptions?

Organization	Yes or No	Question 2 Comment
Florida Municipal Power Agency (FMPA) and Some Members	Yes	Although FMPA agrees with the intent of the Measures, FMPA is concerned that the measures M1 and M2 may not meet the purpose of the measures as stated in the latest draft version of the Standard Processes Manual, which states that that a Measure "(p)rovides identification of the evidence or types of evidence needed to demonstrate compliance with the associated requirement." Instead, M1 and M2 provide examples of evidence that would be used to determine non-compliance, not used to determine compliance.
American Electric Power (AEP)	Yes	American Electric Power agrees with this change.
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	BGE agrees with the R3 text in the latest draft of FAC-003-2.
Dominion	Yes	Dominion agrees and finds this approach superior to existing which sometimes appears to be more administratively focused.
JEA	Yes	Given the basic performance required in R1 and R2 of this version, I agree that specifics about what is included in the plan are not needed. Each entity should be encouraged to write their plan so that the occasional human errors and failures that are inevitable still lead to compliance with the performance aspects of this standard. The team should be sure that the measures do not require unfailing perfect execution of this procedure so that entities are encouraged to minimize this document.
ITC Holding	Yes	ITC feels that this draft is an improvement by clarifying the action expected by this requirement ("competency-based" program specific methodology documentation) and separating other implementing ("risk based") actions from FAC-003-1 as new requirements within this draft version. ITC also agrees with results-based reliability, a standard principle that is driven by relevant reliability requirements and measureable results rather than prescriptive requirements driven by documentation.The term "bulk power system" should not be used in the comment form or any other documentation associated with FAC-003-2.
Independent Electricity System Operator	Yes	Old Requirement R1 has been distilled down to its essential elements with the removal of the detailed sub-requirements that were previously included. This places the onus of developing an effective transmission vegetation management program (TVMP) on the asset owners where it ought to be, since they have the requisite expertise. Guidance is however provided in the Technical Reference document to assist Transmission Owners in developing a TVMP that in their view works for them, and achieves the overall objective of preventing those vegetation related outages that could lead to Cascading. By specifying the "what" appropriately and leaving the "how" to the entity, the entity is now in the best position to determine the most effective deployment of its resources for meeting the goals of the standard.

Organization	Yes or No	Question 2 Comment
CenterPoint Energy	Yes	R3 focuses on its intended impact on Sustained Outages without being overly prescriptive.
Southern California Edison Company	Yes	SCE prefers the results-based approach to crafting reliability standards because it provides utilities with the necessary flexibility to develop internal criteria based on widely accepted best practices and industry innovations.
Western Area Power Administrtaion	Yes	The old Draft 2 version of R1 was developed to give the regulatory entities substantial and tangible information from which to judge the adequacy of a TO's overall approach to program management. The old Draft 2 version of R1 was purposely crafted in this detailed manner as an alternative to attempting to manage the problematic CCZ concepts contained in Draft 1. Industry strongly rejected the CCZ management concepts contained in Draft 1 in the first comment period. It appears that the current Draft 3 version of R3 has lost some of the content needed to fully substitute for the management of Draft 1 CCZ concepts. The addition of an implementation requirement intended to measure the full execution and success of the overall management approach identified by a TO in response to the new R3 may help to address this shortcoming. As currently worded, the requirement to simply execute a flexible annual work under the new R7 in Draft 3 does appear extensive enough to fulfill this need.
Oncor Electric Delivery	Yes	The RBS defense-in-depth strategy for this Standard does provide an adequate level of reliability. The Standards purpose statement refers to the electric Transmission system and corresponding applicable lines not the BPS or BES as currently defined in the NERC glossary or being proposed (NOPR) RM09-18-000. Removing prescriptive requirements allows utilities flexibility to document their program and perform their vegetation management to achieve the goal of no outages that lead to cascading.
IRC Standards Review Committee	Yes	The SRC agrees with the intent of R3, but questions the need for inspection postponements to be limited to natural "disasters". A well-planned inspection may be delayed by a common lighting storm. While there is a need to conduct the inspections and those inspections could be done anytime within the TO's own plans - the SDT may want to modify the exception to be natural disasters or other conditions that are reported within 5 business days and agreed to as an excused condition by the Regional Reliability Organization.
Southen Company	Yes	The term “bulk power system” should not be used in the comment form or any other documentation associated with FAC-003-2.
Progress Energy Carolinas	Yes	This separates implementing actions such as inspections, annual plans and imminent threat procedures from TVMP methodology (which proves competency of the program).This draft is an improvement by clarifying the action expected by this requirement (“competency-based” program specific methodology documentation) and separating other implementing (“risk based”) actions from FAC-003-1 as new requirements within this draft

Organization	Yes or No	Question 2 Comment
		version.
SERC OC Standards Review Group	Yes	This separates implementing actions such as vegetation inspections, performing annual work plans and responding to imminent threats from the required documentation of the TVMP methodology (which proves competency of the program).This draft is an improvement by clarifying the action expected by this requirement (program specific methodology documentation requirement) and separating other implementing actions from FAC-003-1 as new requirements in this draft version.
SERC Vegetation Management Sub-committee	Yes	This separates implementing actions such as vegetation inspections, performing annual work plans and responding to imminent threats from the required documentation of the TVMP methodology (which proves competency of the program).This draft is an improvement by clarifying the action expected by this requirement (program specific methodology documentation requirement) and separating other implementing actions from FAC-003-1 as new requirements in this draft version.
Western Area Power Administration - Upper Great Plains Region	Yes	WAPA - UGPR agrees with a reliability based standard. In the plains states, we have fewer trees than many utilities, so having prescriptive requirements that assume we have lines running through forested areas seems to mandate an excessive amount of detail. We prefer to keep our program very simple -- perform periodic inspections to identify vegetation problems and then direct applicable resources in to take care of the problem. Our hope is that a results-based reliability standard will provide some flexibility for those utilities with smaller scale vegetation encroachments.
Ad Hoc Group subteam formed to review draft standard	Yes	While the new R3 is less prescriptive than the old R1, it appears to stray from criteria #4 for developing results-based standards, as described in this comment form. It appears to require only the development of a document. We understand that in some cases this cannot be avoided. We believe that this is one of those cases where the reliability objective of building competency in considering all possible locations the conductor may occupy and assuming operation within Rating and Rated Electrical Operating Conditions over-rides our reluctance in requiring a registered entity to produce a document rather than a result. We suggest that in a future revision to standard that this can be combined with R7 to create a comprehensive requirement that the entity have a vegetation management program that demonstrates it is able to perform those actions necessary to keep vegetation out of the MVCD.
KCPL	No	The measures for R1 and R2 are zero tolerance for encroachments into the MVCD that did not result in a “contact” with the transmission facility. Considering the substantial number of miles of transmission involved, the complexities in anticipation of vegetation growth with numerous growth variables, vegetation management limitations imposed by other regulations or requirements, and unexpected transmission events that require substantial efforts regarding physical restoration, it is not reasonable or practical for the measures here to include encroachments that do not result in an interruption of transmission service. Recommend the SDT

Organization	Yes or No	Question 2 Comment
		consider modifying the measures for R1 and R2 to be applicable only in the interruption of a transmission facility.

3. Do you agree with the overall layout of the proposed template? If not, please suggest an alternative layout.

Summary Consideration: Most comment forms (43 out of 53) indicated agreement with the overall layout of the proposed template. However, some expressed concerns over individual parts of the template. The Vegetation Management SDT and the Standards Committee Process Subcommittee (SCPS) appreciate the commenters' comments and suggestions.

Some commenters do not agree with grouping Measures and Requirements together on the basis that Measures are compliance related elements and hence should be grouped with the compliance elements. This suggestion was not adopted. The SCPS asked a specific question about putting the requirements and measures together, and 50 of the 52 comment forms indicated support for this change.

Some commenters proposed that the Text Boxes are not needed if standards are written clearly; others expressed a concern that the material in the text boxes may be taken as mandatory, or used by the auditors as guidelines for assessing compliance. Some suggested that it is necessary to have a clear declaration on which parts/elements in the standards are mandatory. While the rationale for a requirement may be clear to most people who are familiar with the topic addressed by the standard, as the industry grows and people unfamiliar with the industry try to understand each requirement, documenting the rationale for each requirement is expected to be useful. The Text Boxes that provide the "rationale" for each requirement and other explanatory information will remain in the body of the standard until it is balloted, but will be removed from the approved version of the standard. Their content will be moved to the Guideline and Technical Basis Section.

The subcommittee will ask that NERC's legal department to write a statement for addition to each standard to clarify which parts/elements of the standard are mandatory and enforceable and which are provided only as information.

Some commenters raised a concern over the administrative elements. Some are unsure whether or not these elements are mandatory and asked if they are mandatory, then why they are not included in the Requirement Section. These commenters suggested that if the administrative reporting is not mandatory, does it belong in the standard, or should the Rules of Procedure Section 1600 be used to collect the data or document.

Some suggested that the Guideline and Technical Basis Section does not belong to a standard; others suggested that the material in the Guideline and Technical Basis Section be moved to appendices. Some suggested that the materials in the text boxes can also be regarded as providing the 'technical basis' and as such, can also be moved to appendices. Some commenters suggested moving the Guideline and Technical Basis Section to immediately after the Requirements and Measures section for ease of reference and this suggestion was not adopted. The compliance elements of the standard include evidence retention as well as other information that is mandatory, and the SCPS believes this should appear before the elements of the standard that aren't mandatory.

Some commenters do not support moving VRFs and Time Horizons away from the Requirements to be grouped together with the VSLs. They expressed a desire to be able to see the VRF associated with each Requirement to know the violation impact. The SCPS will modify the format to put the information in both places – adjacent to the requirement and in a separate table.

Some commenters expressed a concern with putting the Development Plan, Definitions, Effective Dates and Revision History at the front end since the readers must screen through 4-5 pages before getting to the standard itself. Some commenters suggested that these housekeeping items be moved to the end, other commenters suggested putting the Background Section before the Applicability Section in the Introduction. The table with effective dates was removed as this will be challenging to keep up to date, however the other sections of the standard will remain where proposed with the exception that the Definitions Section will be moved ahead of the Background Section.

Some commenters indicated that there appears to be some redundant verbiage in the Background Section and the Guideline and Technical Basis Section. The SCPS will bring this to the attention of the VM SDT. These two sections were intended to have two distinctly different purposes – the Background Section identifies “why” the standard exists, and the Guideline and Technical Basis Section provides information that may be useful to entities in applying the standard.

Some commenters suggested using color code to differentiate between the information that is meant to be temporary and the information that is expected to stay with the standards. This suggestion was not adopted.

Organization	Yes or No	Question 3 Comment
American Transmission Company	No	a.) ATC believes that the “Guideline and Technical Basis” section does not belong within the NERC Standard. ATC feels there are parts of this section that appear to obligate the TO with additional mandatory requirements. (please refer to additional details in Question #8 below) b.) ATC believes the “Measures” section immediately following the Requirement is helpful and placement is appropriate, however, the introductory statement in R1 and R2 is poorly worded. For example, M1 currently states: “ Evidence of violation of Requirement R1 is limited to:” ATC feels this is a negative approach and recommends that it be stated in a positive manner such as”” Evidence of compliance to R1 would be to: o Not have any vegetation-related Sustained Outages due to a grow-in.” c.) ATC would like to clarify whether the “Rational” boxes remain within the final standard. It seems appropriate to have this information but that it would be better to have this information appear in the “Guideline and Technical Basis” section.
GCPD	No	Don't need all the extra requirements beyond R2.
Florida Municipal Power Agency (FMPA) and Some Members	No	FMPA appreciates the improvements and has additional suggestions. Please see responses to the remainder of the questions, and below, for suggestions:The evidence retention should be grouped with the Measures for ease of creating a records retention schedule for the standards and requirements.Do we really need a “Compliance Monitoring and Enforcement Processes” section of the standards? Are there any standards that don’t have all of these activities?
City of Tallahassee (TAL)	No	I would delete the Rationale in favor of keeping the Guideline and Technical Basis. The Guideline appears to be more in-depth than the Rationale. This makes the Rationale unnecessary.
Northeast Power Coordinating Council	No	NPCC participating members want to thank the drafting team for the hard work devoted to developing this standard, and recognize the difficult issues of producing the first “results based” proof of concept standard and offer the following, not as criticism, but as helpful suggestions for their consideration based on a cross section of stakeholder reactions to the draft. 1) Measures are compliance related elements and should not

Organization	Yes or No	Question 3 Comment
		appear immediately after the requirements. The older template had the compliance elements grouped together in a separate section, and we suggest this continues. In the past there have been instances of RSAW (Reliability Standards Audit Worksheets) not clearly matching the standard's requirements or measures. We suggest that this initiative with a results based requirement consistently involve the development of the associated RSAWs to ensure coordination, and also that the requirement results in a performance based, competency, or risk based reliability criterion. 2) Effective dates have become a complex issue. We suggest that rather than having an effective date table in the standard, this type of information be restricted to the implementation plan and ultimately reside in a NERC relational database which is currently under discussion/development. NPCC participating members suggest that the "Effective Dates" section be replaced with "NERC BOT Adopted Date". Due to their complexities, FERC and Provincial approvals are something best left to implementation plans and databases. 3) "Rationale" boxes appearing in the Requirements section are problematic. If a "Rationale" box is required to explain part of the requirement then the requirement needs to be revised. For example, in R7 the requirement states that a TO shall execute a flexible annual vegetation management plan. Flexible in this context could have many different interpretations, yet in the "Rationale" box the use of the word flexible is clearly delineated to mean work may be deferred if not an imminent threat. In general we believe these boxes add little value, and if the requirement can't be understood without the "Rationale" then the requirement needs to be worded appropriately. Suggest these types of explanatory statements go into guidance documents, or supporting technical documents, and do not appear in the "Requirements" sections. 4) Also, there seems to be some confusion regarding the Administrative Procedure section. There seems to be requirements embedded within it, e.g. "The Transmission Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of transmission lines determined by the Transmission Owner...." Is this an enforceable aspect of the standard? If so, are there any other documents such as the NERC Rules of Procedure "ROP" or compliance related documents such as the CMEP that have to be changed? NPCC participating members recognize that this is a results based standard. Administrative requirements should be removed from the standards, and dealt with elsewhere (such as the ROP). 5) The Guideline and Technical Basis section contains valuable information, but this adds to the volume of the document. The Drafting Team should consider moving this to a separate document. In viewing the standards as a whole, the FAC-003 standard is relatively straightforward when compared to the developing of other standards such as the TPL standard. A similar approach, if applied to the TPL would result in a standard with potentially hundreds of pages. If the type of work appearing in this section is envisioned for other more complex standards such as TPL, the DT should consider separating out this section as a single supporting document. 6) Do FERC and the Provincial governmental authorities approve just the requirements in the Standard, or the whole package?
FRCC Manager of Operations	No	See responses to #8, 10, 11 and 13.
IRC Standards Review	No	The proposal to move the time horizon and the VRF to a separate independent section is not useful. Take for example R1 and R2 of the proposed standard. A careful read of the two requirements and measurements

Organization	Yes or No	Question 3 Comment
Committee		would indicate that there is no difference between them and that it would be better to have one requirement for all conductors. It is not until the reader gets to the compliance section does the VRF difference show up. There is no savings to removing the previous format's parenthetical inclusion of time horizon and VRF at the end of the requirement. The Independent Section can contain all of the proposed information but don't remove it from the requirement. The format of the standard would not be an issue if NERC would develop a standards database. Then, the database could be queried in any format the user desires.
ERCOT ISO	No	The Standard itself is several pages into the document. The VRFs/VSLs should be in the Requirements/Measures Section. The Background, Rationale, Administrative Procedures are additional information and should be located in an Appendix so it doesn't clutter the Standard.
CenterPoint Energy	No	We suggest combining and moving the Rationale, Background, Guideline and Technical Basis, and Technical Reference to a consolidated appendix because there is much duplication in the wording within each of these sections, and independently they may be misinterpreted as being an integral part of the Requirements and Measurements which they are not. The Requirements and Measurements should stand clearly on their own. The appendix should contain examples of how to meet the requirements under various circumstances. The appendix should be supplementary and optional to the Standard.It is also not clear if the Administrative Procedure is a mandatory activity. It would be helpful if the intent of this section was stated within the Standard.
NERC Staff (12 staff members)	No	We suggest using two colors for explanatory information - yellow for information that is temporary - such as the information explaining the difference between the approved and proposed definitions of "Vegetation Inspection" - and using blue for all boxes that are intended to remain in the approved standard.We feel that the Standards Committee Process Subcommittee should pursue adding a statement from NERC's legal department indicating which parts of the standard are enforceable. In the meantime, we suggest using the standard template in order to clearly define the enforceable parts of the standard. The section identified as "Guideline and Technical Basis" is not really a guideline (typically a proposed process for completing work) and is not really a "technical basis" (typically a summary of research or engineering judgment, etc. used to explain the reasoning for something). The information in this section is explaining how the drafting team expects compliance with the requirements to be measured. We suggest revising the heading to "Application Guidelines." This is the term that was originally proposed by the Results-based team and is the heading identified in the proposed Standard Processes Manual.
Ad Hoc Group subteam formed to review draft standard	Yes	
Arizona Public Service Company	Yes	

Organization	Yes or No	Question 3 Comment
Bonneville Power Administration	Yes	
Central Maine Power, Iberdrola USA	Yes	
Cleco	Yes	
Consumers Energy	Yes	
Duke Energy	Yes	
Entergy Services	Yes	
Exelon	Yes	
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
Nebraska Public Power District	Yes	
North Carolina EMC	Yes	
Omaha Public Power District	Yes	
Oncor Electric Delivery	Yes	
Orange and Rockland Utilities, Inc.	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	

Organization	Yes or No	Question 3 Comment
Southen Company	Yes	
Southern California Edison Company	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	
Xcel Energy	Yes	
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	BGE is supportive of the proposed template.
JEA	Yes	Coupling the measures and rationale with each requirement make the standard easier to follow and to implement.
Dominion	Yes	Dominion agrees, but suggests that reference(s) to figure(s) and table(s) contain links that can take reader to that section of the document. This is superior to having to scroll through document. If the reference(s) is external to this standard document, links may be harder to manage but should at least reference a common webpage(s) used by NERC for the posting of such documents.
ITC Holding	Yes	ITC feels that the overall layout of the standard (a) improves readability, (b) clarifies expectations, (c) reduces confusion associated with referencing between pages, and (4) allows for background information and the SDT rationale to accompany the standards but we would suggest locating Guideline and Technical Basis after Requirements and Measures for better reference accessibility.
MRO's NERC Standards Review Subcommittee	Yes	N/A
Tampa Electric Company	Yes	None
Western Area Power Administration - Upper Great	Yes	None

Organization	Yes or No	Question 3 Comment
Plains Region		
FirstEnergy	Yes	Overall, we like the layout of the standard, especially the Effective Date table in the front of the standard, the combination of Requirements and Measures, and the grouping of the VRF, Time Horizons, and VSL into one table. However, we would like to see a clearer delineation between the mandatory requirements and the guidance and rationale information. The standard should explicitly be clear as to what is mandatory and what is not, which may even require moving the "Rationale" text boxes out of the Requirements and Measures section. FE believes the information presented in the Rationale text boxes can be effectively covered in the "Guidelines and Technical Basis".
Western Area Power Administrtaion	Yes	The format could be enhanced by moving the Guidelines and Technical Basis section forward to be included with the corresponding Requirement, Measure, and Rationale. This would be helpful because it is awkward flipping back and forth between these two sections when trying to fully understand a requirement.
Pepco Holdings, Inc. - Affiliates	Yes	The general layout is quite effective. Still, it would be good to keep the VRFs and time horizons within the text of the requirement.
Ga Transmission Corp	Yes	The layout is adequate but many things are needing further explanation such as the MVCD.
Progress Energy Carolinas	Yes	The overall layout improves readability, clarifies expectations, reduces confusion associated with referencing between pages, and allows for background information and SDT rationale to accompany the standards (reducing the need for interpretation).
SERC OC Standards Review Group	Yes	The overall layout improves readability, clarifies expectations, reduces confusing references between pages, and allows for background and rationale to accompany standards.
SERC Vegetation Management Sub-committee	Yes	The overall layout improves readability, clarifies expectations, reduces confusing references between pages, and allows for background and rationale to accompany standards.
East Kentucky Power Cooperative, Inc.	Yes	The overall layout is greatly improved. This draft is easier to read and understand and clarifies the expected actions required in the standard.
American Electric Power (AEP)	Yes	The overall template layout is acceptable
Tennessee Valley Authority	Yes	This aids the understanding of the standard.

Organization	Yes or No	Question 3 Comment
Ameren	Yes	This draft is much more user friendly and easier to follow; appreciate the follow up information.
Consolidated Edison Company of New York, Inc.	Yes	We do believe the overall layout is effective but the SDT should consider putting the Background Section before the Applicability Section in the Introduction and also try to reduce any redundant verbiage in the Background Section and the Guideline and Technical Basis Section. A twenty-one page Standard is too lengthy and the supporting Technical Reference document properly addresses many of the issues mentioned in the Guideline and Technical Basis Section.
KCPL	Yes	

4. Do you agree with grouping the standard development timeline (previously called roadmap) with the revision history, and the effective date(s) and putting this administrative information up front before the Introduction Section? Please explain.

Summary Consideration: A vast majority of the comment forms (48 out of 52 who responded to this question) indicated support for grouping the Development Timeline, Revisions History and Effective Dates and putting them up front before the introduction Section.

Some commenters suggested moving this group of information to the end, other commenters suggested that the Definition Section be taken out of the group and placed just before Introduction. The SCPS does not think that moving the grouped information to the end will result in much improved readability. Readers can get to the beginning of a standard as quickly by scrolling or flipping through the pages.

The SCPS agrees with moving the Definition Section to just before the Introduction Section since Definitions are part of the balloted materials and the team adopted this suggestion. Note that after the standard is balloted, the definitions, if approved, are moved out of the standard and into the Glossary of Terms Used in Reliability Standards.

Some commenters suggested adding a table of contents. The SCPS will consider this in the next posting.

Organization	Yes or No	Question 4 Comment
IRC Standards Review Committee	No	For this standard one must read through 7 pages before getting to the reason for the posting. The administrative information should be relegated to the end of the posting not the beginning.Under exceptions in the Effective Dates section of the standard, IROLs are referenced as only being created by the Planning Coordinator. Because Reliability Coordinators must also establish IROLs per FAC-011 and FAC-014, we suggest that reference to the Planning Coordinator should be redacted and IROLs should be discussed regardless of whether the Planning Coordinator or Reliability Coordinator creates them.
Consolidated Edison Company of New York, Inc.	No	The only issue we have with the administrative information being before the Introduction Section is with the Definition of Terms Used in the Standard Section. We feel this should be part of the Introduction and not a stand alone section.
Orange and Rockland Utilities, Inc.	No	The only issue we have with the administrative information being before the Introduction Section is with the Definition of Terms Used in the Standard Section. We feel this should be part of the Introduction and not a stand alone section.
ERCOT ISO	No	This information should be located at the end so that it doesn't distract from the main purpose of the Standard. It is cumbersome to read through several pages before getting to the actual language of the Standard.
Ad Hoc Group subteam formed to	Yes	

Organization	Yes or No	Question 4 Comment
review draft standard		
American Transmission Company	Yes	
Arizona Public Service Company	Yes	
Bonneville Power Administration	Yes	
Central Maine Power, Iberdrola USA	Yes	
City of Tallahassee (TAL)	Yes	
Cleco	Yes	
Consumers Energy	Yes	
Duke Energy	Yes	
Exelon	Yes	
GCPD	Yes	
JEA	Yes	
Manitoba Hydro	Yes	
Nebraska Public Power District	Yes	
NERC Staff (12 staff members)	Yes	
North Carolina EMC	Yes	
Omaha Public Power District	Yes	

Organization	Yes or No	Question 4 Comment
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	
Southen Company	Yes	
Tennessee Valley Authority	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	
Western Area Power Administrtaion	Yes	
Ameren	Yes	Appreciate the ability to reference up front.
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	BGE agrees with the proposed grouping and placement of these items.
Dominion	Yes	Dominion agrees that the new format is superior to the old. However, we suggest a table of contents be added to include at a minimum, sections for (1) Definitions of Terms Used in Standard (2) Effective dates, (3) Introduction, (4) requirements and measures (5) Compliance (6) Time Horizons, VRF and VSLs (7) Administrative (8+) guidelines, technical basis, tables or figures referenced in standard.
Entergy Services	Yes	Easy to follow.
Ga Transmission Corp	Yes	I do not see a problem with this change.

Organization	Yes or No	Question 4 Comment
Xcel Energy	Yes	It is acceptable to do so, however it is not clear as to how the effective date portion will be incorporated in a final version of the standard. Will there be some kind of cover page to at least indicate the standard or will it just be a small title bar at the top? (i.e. - what does page 1 of the standard look like?)
ITC Holding	Yes	ITC agrees with locating the revision history and administrative information before the introduction. This alignment improves clarity and readability by providing a single location for this information.
Florida Municipal Power Agency (FMPA) and Some Members	Yes	Just a question, when the standard becomes effective, how will it be posted? FMPA assumes that this section will move to the end of the standard instead of the front when approved.
CenterPoint Energy	Yes	No preference.
Tampa Electric Company	Yes	None
Northeast Power Coordinating Council	Yes	NPCC participating members believe this is acceptable. However our previous response to question 3 above still applies regarding the Effective Date section. It should be removed from the standard, and either appear in an implementation plan, or more effectively in a NERC relational database.
Independent Electricity System Operator	Yes	Since in this case the effective dates of all requirements are all the same, we believe the effective dates table could be significantly condensed.
East Kentucky Power Cooperative, Inc.	Yes	The format provides for better clarification and is easier to read and comprehend.
MRO's NERC Standards Review Subcommittee	Yes	The NSRS likes the way the standards is now formatted and finds it more user friendly.
American Electric Power (AEP)	Yes	These changes make sense to American Electric Power.
SERC OC Standards Review Group	Yes	This format adds clarity and improves readability.
SERC Vegetation Management Sub-committee	Yes	This format adds clarity and improves readability.

Organization	Yes or No	Question 4 Comment
Progress Energy Carolinas	Yes	This grouping improves clarity and readability by providing a single location for this information.
Western Area Power Administration - Upper Great Plains Region	Yes	WAPA - UGPR is neutral on location of these items.
Southern California Edison Company	Yes	We agree that grouping the administrative information up front is logical and makes for a cleaner presentation.
FirstEnergy	Yes	We agree with having a detailed table showing the effective dates of each requirement. However, we would like to see NERC go back into the table and specify the dates of NERC and FERC effective dates once they are known. Having the statement "1st day of the 1st quarter one year after applicable regulatory approval" in the standard does not help the user of the standard when they are working towards compliance, and requires them to go elsewhere to find when the approvals took place. All this information should be in the standard when available and NERC staff should be afforded the latitude to do so even without needing to use its Errata process. Placing the dates directly within the standard is more convenient for the end user.
KCPL	Yes	

5. Do you agree with grouping the Requirements and Measures together, in one Section now called Requirements and Measures? Please explain.

Summary Consideration: A vast majority of the comment forms (50 out of 52) indicated support for grouping the Requirements and Measures in one Section.

Some commenters suggested moving the Measures back to the Compliance Section and adding a reference to each Measure stating which Requirement it refers to. The SCPS does not think that moving the Measures back to the Compliance Section will result in any improvement in readability. Keeping the Measures together with the Requirements provides readers with a clear and easy view of what evidence needs to be provided to demonstrate compliance with the Requirements.

Organization	Yes or No	Question 5 Comment
Xcel Energy		We are indifferent as to the placement of the Measures, however it does appear to create awkward shaped paragraphs when Requirements and Measures are place around Rationale boxes.
Northeast Power Coordinating Council	No	As commented earlier in question 3, this is a compliance related issue and should be in the Compliance section. NPCC participating members believe clear concise requirements should be the focus, and inserting measures immediately after the requirements adds little value. In addition, RE compliance staffs who use the metrics find no value to moving it as well. This format would ease working with the document as a working draft, but should not be in an adopted document. Consider moving Measures back to the compliance section, and add a reference to a Measure's wording stating which requirement the measure refers to. Only adding a statement when the Requirement and Measure numbering don't line up could be considered.
Bonneville Power Administration	Yes	
Cleco	Yes	
Duke Energy	Yes	
IRC Standards Review Committee	Yes	
Manitoba Hydro	Yes	
Nebraska Public Power District	Yes	
NERC Staff (12 staff members)	Yes	

Organization	Yes or No	Question 5 Comment
North Carolina EMC	Yes	
Omaha Public Power District	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	
Southen Company	Yes	
Southern California Edison Company	Yes	
TO/TOP	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	
Western Area Power Administrtaion	Yes	
Central Maine Power, Iberdrola USA	Yes	Adds clarity between requirements and measures .
Arizona Public Service Company	Yes	APS doesn’t agree with all of the requirements.
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG,	Yes	BGE agrees it makes sense to group these two sections together.

Organization	Yes or No	Question 5 Comment
CNE & CENG)		
JEA	Yes	Coupling the measures and rationale with each requirement make the standard easier to follow and to implement.
Dominion	Yes	Dominion finds this format improved over the existing as reader can more easily correlate the requirement (process/procedures) to the measure (evidence).
Exelon	Yes	Exelon agrees this is a good practice that will help ensure Requirements and Measures are aligned
Florida Municipal Power Agency (FMPA) and Some Members	Yes	FMPA agrees that grouping the Requirements and Measures together in one section is a great idea; however, to realize even more benefit, we now have the opportunity to eliminate redundant wording, e.g., M3 can be shortened to: “A documented transmission vegetation management program” and eliminate the rest of the words that are redundant with R3.
Entergy Services	Yes	Great addition and improvement!! Much clearer and easier to follow.
City of Tallahassee (TAL)	Yes	However, if you keep the Rationale text boxes, keep the Measures in the same column as the requirement. This will result in a more consistent “look and feel” to all the requirements (M3 for R3 is the example).
FRCC Manager of Operations	Yes	In addition the DT could also eliminate redundant wording in the standard requirement, e.g., M3 can be shortened to: “A documented transmission vegetation management program” and eliminate the rest of the words that are redundant with R3 or use words in the measure that refer back "to the requirement above".
ERCOT ISO	Yes	Including a specific measure with each requirement adds clarity; however, it isn’t clear whether each measure is exclusive to the requirement that it follows. Is it possible that some requirements will have multiple measures that are not listed immediately following the requirement?
ITC Holding	Yes	ITC agrees with Requirements and Measures grouped together
GCPD	Yes	Makes the standard template much easier to read and use.
Consumers Energy	Yes	Much easier to follow in this format.
Ameren	Yes	Much more user friendly to be able to see the requirement and the measurement together for clarification.

Organization	Yes or No	Question 5 Comment
CenterPoint Energy	Yes	No preference.
MRO's NERC Standards Review Subcommittee	Yes	NSRS prefers to have the requirements, measures, VRFs, VSLs and Time Horizons together instead of referencing to another page or part of the standard.
American Transmission Company	Yes	See ATC's comment on "Measures" in Question #3 above.
Tennessee Valley Authority	Yes	This aides in understanding of the standard. Grouping the VSL and VRF for each requirement along with the measurement could be beneficial too.
Ga Transmission Corp	Yes	This also is OK no problem with the layout.
Progress Energy Carolinas	Yes	This change also improves readability and improves understanding of the requirement.
SERC OC Standards Review Group	Yes	This format adds clarity and improves readability.
SERC Vegetation Management Sub-committee	Yes	This format adds clarity and improves readability.
East Kentucky Power Cooperative, Inc.	Yes	This format provides for better readability and clarification.
Tampa Electric Company	Yes	This improves the clarity and understanding to the requirements.
Independent Electricity System Operator	Yes	This is useful to avoid having to move back and forth between separate sections to find out what is needed to show that a requirement is met. We do not have a strong preference for this re-grouping however.
Western Area Power Administration - Upper Great Plains Region	Yes	WAPA - UGPR believes this makes it easier to identify the requirement and what we need to provide to demonstrate with are in compliance with the requirement.
FirstEnergy	Yes	We agree that grouping the Requirements and Measures together is convenient when utilizing the document for compliance.

Organization	Yes or No	Question 5 Comment
Consolidated Edison Company of New York, Inc.	Yes	We agree with grouping the Requirements and Measures together since it does add another level of clarifying description for our field forces who are ensuring compliance during vegetation management activities. The Measures for R1 and R2 describe evidence of violation while the Measures for the remaining Requirements R3 - R7 describe evidence of compliance. All Measures should be written consistently as either evidence of compliance or evidence of violation.
Orange and Rockland Utilities, Inc.	Yes	We agree with grouping the Requirements and Measures together since it does add another level of clarifying description for our field forces who are ensuring compliance during vegetation management activities. The Measures for R1 and R2 describe evidence of violation while the Measures for the remaining Requirements R3 - R7 describe evidence of compliance. All Measures should be written consistently as either evidence of compliance or evidence of violation.
Ad Hoc Group subteam formed to review draft standard	Yes	We agree with the understanding that the specific requirements of the standard are the enforceable elements of the standard. The rationale and measures add clarity to support a results-based requirement.
American Electric Power (AEP)	Yes	Yes, this is a more readable format.
KCPL	Yes	

6. **Do you agree with grouping VRFs, Time Horizons and VSLs together, and putting them in a table separate from the Requirements and Measures Section? Please explain.**

Summary Consideration: A vast majority of the comment forms (47 out of 54) indicated support with grouping VRFs, Time Horizons and VSLs together.

Some commenters suggested moving the VERs and Time Horizon back to the Requirements.

Some commenters agree with grouping VRFs, VSLs and Time Horizons together, but expressed a desire to also see the VRFs and Time Horizons in the Requirements as well. The SCPS adopted this suggestion in the next posting.

Some commenters suggested listing the applicable table rows with each requirement to consolidate all pertinent information with the requirement. The SPCS believes that this will convolute the Requirements and Measures Section with little added value.

Some suggested adding the penalty matrix to facilitate discussions with property owners/agencies resisting maintenance activates. The SCPS does not believe the penalty matrix is a standard element or technical reference material. This suggestion was not adopted.

Some commenters indicated that although a non-binding poll is taken of the VRFs and VSLs, it appears that the Time Horizons are part of the standard that is still subject to stakeholder ballot. Commenters suggested that the SDT should explain how this will be made clear to balloters and asked if there is an intent to modify the standards process to remove the time horizons from the portions of the standard that are subject to ballot.

In response to the above suggestions, the SCPS will retain the grouping as proposed, but will also put Time Horizons and VRFs adjacent to their associated Requirements.

Organization	Yes or No	Question 6 Comment
Pepco Holdings, Inc. - Affiliates	No	Agree that the grouping of the subject material is appropriate, but it is not necessary to also remove the VRFs and time horizons from the requirement.
JEA	No	I would prefer to have the VRF’s and time horizons together with the requirements and measures section. The VSL’s separate is appropriate as that is not information needed while complying, but only after a failure.
Manitoba Hydro	No	If the VRF’s Time Horizons and VSLs were listed in with each requirement and measure section, it would eliminate the need for cross referencing 2 sources of information.
Oncor Electric Delivery	No	It would be nice to see the associated VRF’s and Time Horizon with the requirements. No text, but referenced.
ERCOT ISO	No	The associated VRFs/Time Horizons/VSLs should be identified alongside each Requirement so that all relevant criteria for a given Requirement are organized together.

Organization	Yes or No	Question 6 Comment
IRC Standards Review Committee	No	While we agree that the grouping of the subject material is appropriate, it is not necessary to also remove the VRFs and time horizons from the requirement.
Duke Energy	No	While we like grouping VRFs, Time Horizons and VSLs together in a table, we would also like to see each VRF and Time Horizon listed with its requirement. It's a small amount of information that we think adds value in both places.
Ad Hoc Group subteam formed to review draft standard	Yes	
Ameren	Yes	
American Transmission Company	Yes	
Arizona Public Service Company	Yes	
Bonneville Power Administration	Yes	
Central Maine Power, Iberdrola USA	Yes	
Cleco	Yes	
Consolidated Edison Company of New York, Inc.	Yes	
Consumers Energy	Yes	
Dominion	Yes	
East Kentucky Power Cooperative, Inc.	Yes	
Exelon	Yes	

Organization	Yes or No	Question 6 Comment
FRCC Manager of Operations	Yes	
Independent Electricity System Operator	Yes	
Nebraska Public Power District	Yes	
North Carolina EMC	Yes	
Omaha Public Power District	Yes	
Orange and Rockland Utilities, Inc.	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	
Southern California Edison Company	Yes	
TO/TOP	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	
Western Area Power Administrtaion	Yes	
Xcel Energy	Yes	
MRO's NERC Standards Review	Yes	Again it is good to have this information together in place of referencing some other page or part of the

Organization	Yes or No	Question 6 Comment
Subcommittee		Standard.
Tennessee Valley Authority	Yes	Also please consider parsing out a copy of each VSL/VRF with in each individual requiremnt and measure part of the standard as mentioned in question 5 above.
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	BGE supports grouping VRFs and VSLs together in a separate table.
Southen Company	Yes	Consider putting the appropriate line from the table with each requirement in the body of the standard in addition to the table format. This does make the standard longer and does introduce some redundancy, but it would make each requirement easier to read and interpret on a “standalone” basis.
City of Tallahassee (TAL)	Yes	I believe this makes it easier to follow the Requirements.
ITC Holding	Yes	ITC Agree's
Florida Municipal Power Agency (FMPA) and Some Members	Yes	Much easier to find and understand
CenterPoint Energy	Yes	No preference.
Entergy Services	Yes	This grouping helps to clarify the manner in which the violations will be ranked.
Progress Energy Carolinas	Yes	This grouping improves the template used by previous versions by providing a single view of the impact and risk that has been associated with each requirement. Progress Energy believes that this change would also be improved if the applicable VRF/VSL/Time Horizon table rows were also listed with each requirement (consolidating pertinent info with the requirement). Another improvement would be including the penalty matrix (or including a URL link) to facilitate Transmission Owner discussions with property owners and other governmental agencies.
SERC OC Standards Review Group	Yes	This improves the template used by previous versions by providing a single view of the impact consideration of each requirement. An improvement would be also listing the applicable table rows with each requirement which consolidates all pertinent info with the requirement. Also, adding the penalty matrix would facilitate discussions with property owners/agencies resisting maintenance activates.

Organization	Yes or No	Question 6 Comment
SERC Vegetation Management Sub-committee	Yes	This improves the template used by previous versions by providing a single view of the impact consideration of each requirement. An improvement would be also listing the applicable table rows with each requirement which consolidates all pertinent info with the requirement. Also, adding the penalty matrix would facilitate discussions with property owners/agencies resisting maintenance activates.
GCPD	Yes	This is audit stuff that does need to stay together.
Northeast Power Coordinating Council	Yes	This is consistent with FERC's determination that these are compliance elements and not part of the standard requirements. It will also assist with compliance determinations.
Western Area Power Administration - Upper Great Plains Region	Yes	WAPA - UGPR is neutral on location of these items.
FirstEnergy	Yes	We agree with grouping these items together. It may also be beneficial to include links directly in the table to explanations of VRFs, Time Horizons, and VSLs so that someone unfamiliar with, for instance, what a "Long-Term Planning" horizon means, they could look it up.
NERC Staff (12 staff members)	Yes	We agree with the idea behind the grouping. However, according to the Reliability Standard Development Procedure - Version 7, although a non-binding poll is taken of the VRFs and VSLs, it appears that the Time Horizons are part of the standard that is still subject to stakeholder ballot. The SDT should explain how this will be made clear to balloters. Is there intent to modify the standards process to remove the time horizons from the portions of the standard that are subject to ballot? This issue needs to be addressed by the Standards Committee Process Subcommittee.
Tampa Electric Company	Yes	With all of the VRFs, Time Horizons and VSLs grouped together it facilitates the overall understanding of these factors as they relate to the standard.
Ga Transmission Corp	Yes	Yes this was a good change.
American Electric Power (AEP)	Yes	Yes; this format is more user-friendly.
KCPL	Yes	

7. **Do you agree with the insertion of text boxes, where necessary, to help readers better understand the basis of the Definitions and Requirements? Please explain.**

Summary Consideration: The majority of comment forms (43 out of 54) agree with the insertion of text boxes.

Some commenters disagree with the insertion as the material in the text boxes will be subject to FERC's review and approval.

Other commenters raised a concern that the materials may become pseudo requirements; others are concerned that the material in the text boxes is also mandatory, or may be used by auditors as guidelines to assess compliance.

Some believed that text boxes are not necessary given there is a Guideline and Technical Basis Section. Some suggested removing the text boxes and moving the material to the Guideline and Technical Basis Section.

Some commenters indicated that some text boxes can be temporary (for example, those associated with a definition). More clarity is needed to distinguish this type of text box in the drafting stage, with the expectation that they will be removed after a standard is approved and the definition becomes effective (and removed from the standard).

The SCPS appreciates these comments and the commenters' concerns. The SCPS agreed to post the text boxes with the working document but move the text boxes into the Guideline and Technical Basis Section to support the standard until it is balloted, but will be removed from the approved version of the standard before it is submitted for adoption and filing with regulatory and governmental authorities. Their content will be moved to the Guideline and Technical Basis Section. The material in the Guideline and Technical Basis Section is intended to provide guidance but is not intended to expand on any of the requirements and is not intended to include any mandatory performance. A legal statement will be added to the standard to make this clear.

Organization	Yes or No	Question 7 Comment
Exelon	No	Additional clarifications should be included in appendices or reference documents. Including them with the requirements and measures will cause confusion concerning what the compliance obligation is. This will introduce uncertainty to the compliance monitoring process.
American Transmission Company	No	Although the test boxes provide some addition help, ATC believes that these text boxes should appear in the Guideline and Technical Basis section and that whole section should appear in a companion document to the standard but not be included as part of the standard. Also, see ATC's comment on Rational in Question #3 above.ATC believes that guidance information should not be reviewed and approved by FERC and the inclusion of such information within the standard opens this language up to FERC's oversight and approval.
Northeast Power Coordinating Council	No	As stated in question 3 above, NPCC participating members believe crisp, clear results based requirements require no further explanation. Requirements must be written so they are clearly understood. Text boxes clutter up the standard. Questions could arise if these add "pseudo" requirements to the standards, and there is any inconsistency in what is stated about requirements. NPCC strongly suggests their removal in favor of

Organization	Yes or No	Question 7 Comment
		clear, measurable, and high quality results based requirements.
City of Tallahassee (TAL)	No	I would delete the Rationale in favor of keeping the Guideline and Technical Basis. The Guideline appears to be more in-depth than the Rationale. This makes the Rationale redundant and unnecessary.
CenterPoint Energy	No	It is not clear how the information in the text boxes will be used to determine compliance with the Requirements and Measures. It appears that in the Definition of Terms Used in Standard section that the text boxes add to the definitions or are footnotes to historical information. The Definitions should stand on their own and be robust enough to ensure they are helpful in determining compliance with the Requirements and Measures. In the Requirements and Measures section, the text boxes appear to contain partial information from the Guideline and Technical Basis, and Technical Reference. In all cases the information is not helpful and provides incomplete information. The text boxes should be deleted and pertinent information to compliance should be incorporated into the Definitions, Requirements, and Measures. Any explanatory text or examples should be moved to an appendix as supplementary and optional to the Standard.
ERCOT ISO	No	It is not clear whether the information in the text boxes is “For Information Only.” While the additional information may be helpful, it appears to add sub-requirements within the Standard. This information could be included under a “Rationale” section in an Appendix. However, if the information clouds the purpose of the Requirements or dictates how to comply, then it should be eliminated completely.
Consumers Energy	No	Not necessary given the “Guidelines and Technical Basis”.
Nebraska Public Power District	No	Text boxes and other supporting information are a benefit to the reader as a clarification guide, but should be placed in something other than the Standard.
IRC Standards Review Committee	No	The concept of text boxes needs further discussion. The idea of using text boxes for clarity and explanation is valuable, but is the material in the text box mandatory? If it includes mandatory material than it is not a good idea - all mandatory requirements must be in the requirement. If the text boxes are retained to explain how a phrase is being used (e.g. to make clear what compound actions apply to what compound time frames), then yes, this approach can be invaluable.
Cleco	No	The inclusion of the text implies additional requirements. Keep quidance to a separate paper.
Arizona Public Service Company	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 7 Comment
Consolidated Edison Company of New York, Inc.	Yes	
Duke Energy	Yes	
FRCC Manager of Operations	Yes	
Manitoba Hydro	Yes	
Omaha Public Power District	Yes	
Oncor Electric Delivery	Yes	
Orange and Rockland Utilities, Inc.	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
Southen Company	Yes	
Tennessee Valley Authority	Yes	
TO/TOP	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	
MRO's NERC Standards Review Subcommittee	Yes	1. We agree. The rationale boxes will cut down on interpretations. 2. Are the rationale boxes part of the approved standards for which registered entities will be audited. Are the rationale boxes federal law?3. Under R3, a reference to the National Electric Safety Code in the rationale box would be helpful. (The goal is to

Organization	Yes or No	Question 7 Comment
		verify that utilities will not be held in violation of this standard when operating beyond the NESC conditions.)
North Carolina EMC	Yes	Additional background in the test boxes is very helpful.
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	BGE agrees this would help clarify the basis of the Definitions & Requirements.
Dominion	Yes	Dominion agrees, but suggests that reference to figure(s) and table(s) contain links that can take reader to that section of the document. This is superior to having to scroll through document. If the reference(s) is external to this standard document, links may be harder to manage but should at least reference a common webpage(s) used by NERC for the posting of such documents.
Xcel Energy	Yes	However, the boxes should be adding clarity, not "defining' terms or stipulating further requirements/criteria that must be met. See MVCD in R1 & R2 and the incorporated Table 2, and comments to #1 & #13 in this form. The standard should be able to convey the requirements without the text boxes or, if the text boxes are used, the purpose and legal import of such boxes should be clarified. Further, it should be clarifed that for text boxes that provide examples (e.g., the boxes on page 2 in the definitions section), such boxes should clearly state that the examples are in no way limitations.
Ga Transmission Corp	Yes	I do like the text boxes.
ITC Holding	Yes	ITC agrees, but would like to suggest that the text boxes include additional pertinent information from the Technical Reference that would be helpful as reliability talking points to the public. Example: (R3): The following is a sample description of one combination of strategies which may be utilized by a Transmission Owner. A Transmission Owner's basic maintenance approach could be to remove all incompatible vegetation from the right of way if it has the right to do so and has no constraints
Ameren	Yes	It's helpful to understand the SDT's logic for requirements, clarification is always appreciated.
GCPD	Yes	May help in cutting down the volume of SAR interpretation requests.
Central Maine Power, Iberdrola USA	Yes	R3 - this may be a good place to describe clearances at time of vegetation management work
Florida Municipal Power Agency	Yes	The clarification is important and will reduce the number of requests for interpretation if interpretation is already provided to some extent. Just a caution about how the text boxes will be used in the audit process,

Organization	Yes or No	Question 7 Comment
(FMPA) and Some Members		clarification concerning their use during compliance monitoring would be great.
NERC Staff (12 staff members)	Yes	The explanatory information posted with the proposed definitions, like the definitions, is only relevant to this standard, and some of the information is only relevant to the point where the definition becomes enforceable. What is the expectation for what will happen to this information in the future? We suggest that the text boxes associated with requirements include a reference to that requirement. (Change “Rationale” to “Rationale for R1”)
Western Area Power Administrtaion	Yes	The format could be enhanced by moving the "Guidelines and Technical Basis" section forward to be included with the corresponding Requirement, Measure, and Rationale. Perhaps the "Guidelines and Technical Basis" could also be combined with the corresponding "Rationale" text box. This would be helpful because it is awkward flipping back and forth between these two sections when trying to fully understand a requirement.
SERC OC Standards Review Group	Yes	This format adds clarity and improves readability.
SERC Vegetation Management Sub-committee	Yes	This format adds clarity and improves readability.
East Kentucky Power Cooperative, Inc.	Yes	This format is simpler, easier to read, understand and implement.
Progress Energy Carolinas	Yes	This format provides clarity and improves readability. Progress Energy believes that having SDT basis information for a requirement in the standard will reduce the need for interpretation and improve the interpretation process for a requirement, if necessary.
Tampa Electric Company	Yes	This improves the clarity and understanding to the requirements.
American Electric Power (AEP)	Yes	This is a good change.
JEA	Yes	This is extremely helpful in understanding the intent of the requirement
Western Area Power Administration - Upper Great Plains Region	Yes	WAPA - UGPR believes that the expanations within the text boxes provided additional useful information.

Organization	Yes or No	Question 7 Comment
Entergy Services	Yes	We agree that text boxes being used for additional clarity is a benefit if used in a correct and clear manner. It needs to be specifically stated in the document that the text boxes are to be used for reference only, entities will not be required to specifically follow the language in the Rationale box, and that each utility should specify their own process for addressing each Requirement. For example....the Rationale box for R4 states that "Verified knowledge includes observations by journeyman lineman, utility arborist, or other qualified personnel.......". Our process will specify exactly who that qualified personnel is (Transmission Specialist or another qualified Entergy Employee in the Transmission Vegetation Group, for example). We will specify this in our internal processes.
FirstEnergy	Yes	We agree that text boxes can be useful for requirements and definitions. However, the SDT may want to consider eliminating the text boxes since this information is already provided in the Guidance and Technical Basis section. Also, we have the following additional comments:General:1. With respect for the rationale text boxes for definitions, it is not clear if these boxes will be retained once the definitions are moved out of the standard and added to the NERC Glossary.2. The rationale text boxes can be beneficial for the requirements, but some of the text boxes in this current draft of FAC-003-2 seem to include prescriptiveness that is not found in the requirement. An example is in the text box for Req. R4, which implies timeliness of notification of an imminent threat with the use of the word "rapid". In the case of R4, the requirement should state that notification be carried out immediately (see our suggested rewording of R4 in Question 13). 3. Although these text boxes are not enforceable for compliance, we are not convinced that an auditor will view this as simply guidance.Specific:1. Definition for Active Transmission Line ROW - Example 3 of Inactive ROW - Consider removing this example; situations where vegetation is left unmanaged on portions of the ROW where double-circuit structures exist with only one circuit strung with conductors poses an unnecessary increased risk for vegetation related outages. 2. Rationale box for Req. R3 - See our comments in Question 23. Rationale box for Req. R4 should be revised to state: "To ensure rapid notification of the responsible control center when an occurrence of an imminent threat condition is verified. Evidence of verified knowledge includes observations by journeyperson, lineperson, utility arborist, or other qualified personnel, or a report verified by these personnel. This notification allows the responsible control center to take the appropriate action until the threat is relieved. Appropriate actions may include a temporary reduction in the line loading or switching the line out of service."4. Rationale box for Req. R5 - (1) The last statement of this box seems incomplete. It should be revised to state: "This requirement is not intended to address situations where the transmission line is not at immediate risk and the work event can be rescheduled or re-planned using an alternate work methodology."; and (2) We suggest revising the first statement to "Legal actions filed by property owners, easement restrictions and other events...."
Southern California Edison Company	Yes	We agree that the insertion of text boxes aids readers in understanding the basis for the Definitions and Requirements.

Organization	Yes or No	Question 7 Comment
Independent Electricity System Operator	Yes	We agree that the side-bars give useful contextual information that is not part of standard. This is good and avoids the reader’s attention being completely redirected to a reference document when seeking clarification of the intent of a requirement. We believe however that these text boxes should be used sparingly and the content should also be brief to minimize possible distractions to the reader.It should also be made clear in the standard that these text boxes are not intended to impose additional requirements and in the event of any perceived conflict, the text of the requirement will take precedence.
South Carolina Electric and Gas	Yes	We agree, however we would like clarification on whether entities can be held accountable for rationale portions of the standard as they are for interpretations that are added to a standard.
Ad Hoc Group subteam formed to review draft standard	Yes	We understand this question to refer to the “rationale” text boxes in this standard. Additional information such as this is useful to the entity in explaining and clarifying the understanding of the drafting team in articulating the requirement and thus supports a fuller understanding of the entity in achieving compliance with the requirement.
KCPL	No	I like information that helps to “guide” and “provide guidance”, however, we already having trouble with information from FAQ’s, White Papers, and other guiding documents creeping into the requirements by auditing teams. The inclusion of “guiding information” in the text of the Standard itself may promote adding to requirements. Although helpful, I recommend removing this text from within the body of the Standard.

8. **Do you agree with the addition of a Guideline and Technical Basis Section to place technical materials and other related information that assists entities in understanding how to comply with the standard but does not contain mandatory actions/activities? Please explain.**

Summary Consideration: Most of the comment forms (38 out of 54) indicated agreement with the addition of the Guideline and Technical Basis Section.

Some commenters expressed a concern over how the materials contained in this Section may be used in compliance monitoring and enforcement.

Some commenters suggested that it should be expressly stated that this section is for information purposes only and is not part of the Standard Requirements. They further suggested compiling all of the “Information Only” materials into an Appendix as a preferred alternative. Others suggested that guideline materials be moved into a separate document.

Some commenters suggested that while this Section contains useful materials, NERC should consider developing a separate set of Guideline documents to afford the industry a knowledge base that is not directly sanctionable for non-compliance.

Some commenters expressed a concern that being located within the standard, the Guideline Section will imply additional requirements for mandatory compliance, or get used by auditors as compliance issues.

The SCPS assesses that the industry likes the idea of having technical guidelines for standards. Guideline materials, whether they are put in a separate document or included in a standard, can be used by anyone to assess compliance with standards. Putting them outside of the standard does not eliminate this possibility.

The material in the Guideline and Technical Basis Section is intended to provide guidance but is not intended to expand on any of the requirements and is not intended to include any mandatory performance. A legal statement will be added to the standard to make this clear. The SCPS believes that as long as it is made clear that only the requirements and provision of evidence are mandatory, any supporting materials can be provided in a standard to aid readers better understand the standard without binding them to complying with the supporting materials. The intent of the description of the elements of a standard in the proposed Standard Processes Manual is to make it clear that there is a distinction between the enforceable sections of the standard and the compliance and supporting information sections of the standard.

Organization	Yes or No	Question 8 Comment
Florida Municipal Power Agency (FMPA) and Some Members	No	Although FMPA agrees that a Guideline and Technical Basis document is important, FMPA has concerns about how this section might be used in compliance monitoring and enforcement. For instance, R4 has a time requirement somewhat embedded in the Guideline and Technical Basis that is not in the requirement in the standard: “The imminent threat process should be implemented in terms of minutes or hours as opposed to a longer time frame for interim corrective action plans”. How many minutes or hours? This adds ambiguity to the standard. If a time limit is desired, it should be in the requirement. There are other examples of items that could be interpreted as requirements in the Guidelines. It should be made clear what the purpose of the Guidelines is in compliance monitoring and enforcement. FMPA suggests publishing two documents in the same fashion that the Functional Model has two documents, one for the standards (e.g., the requirements), and another for technical guidance to the standards (e.g., the Guideline and Technical Basis section) to

Organization	Yes or No	Question 8 Comment
		parallel the structure of the Functional Model and Functional Model Technical Document, which will help make the distinction between CMEP and guidance more distinct.
American Transmission Company	No	ATC disagrees with the above statement that it only assists in understanding how to comply. ATC believes that parts of this section are written so they could be interpreted to contain mandatory actions/ activities. To demonstrate, see example on pg.15, R4, 2nd paragraph states...Two key elements of an acceptable imminent threat procedure are outlined below:..........) It should not be more than a preferred method for implementation or supporting how the TO can meet the standard. NERC needs to clarify how this section was intended to be used. (This as written could become part of a Compliance Audit process)Also, refer to ATC's comment on this section in Question #3 above.
Bonneville Power Administration	No	Consider referencing ANSI A300 part 7 as best management practices for R3. It is currently referenced in the White Paper, and would lend more credibility to the standard if it was inserted in the text box for R3.
ERCOT ISO	No	For the same reasons stated in the comments to Question 7, it should be expressly stated that this section is for information purposes only and is not part of the Standard Requirements. Compiling all of the "Information Only" materials into an Appendix would be the preferred method of organization.
Northeast Power Coordinating Council	No	NPCC participating members do not believe that publishing more information as part of the standard is appropriate. For the same reasons as stated in the preceding response related to "Text Boxes" in question 7, any inconsistency may result in a conflict with a requirement. The information in the Guideline and Technical Basis section is valuable, however, and should be available to the industry in the form of guidelines. NPCC participating members suggest that NERC assemble a comprehensive set of "Guideline" documents into one bookmarked pdf publication to be updated as standards change. This will afford the industry a knowledge base that is not directly sanctionable for non-compliance, but a set of industry best practices, background, and reference for the standards development activities. Also, concern exists that FERC and Provincial governmental authorities will have jurisdiction over "Guidelines", and when the standard is approved it will become a mandatory "rule".
Nebraska Public Power District	No	Same as item 7.
CenterPoint Energy	No	See answer to Q3.
GCPD	No	Should be separate documents. If located with the standard it will get used by the auditors as compliance issues. NO matter how much text you provide to the contrary it will become part of the standard over time.

Organization	Yes or No	Question 8 Comment
Consolidated Edison Company of New York, Inc.	No	Since the SDT has developed a complete Technical Reference Document for this Standard, there seems to be redundancy with the Guideline and Technical Basis Section. This Standard has become too lengthy with all of the additional details and information that has been added. We prefer to have a shorter Standard and a more detailed stand alone supporting reference document.
Orange and Rockland Utilities, Inc.	No	Since the SDT has developed a complete Technical Reference Document for this Standard, there seems to be redundancy with the Guideline and Technical Basis Section. This Standard has become too lengthy with all of the additional details and information that has been added. We prefer to have a shorter Standard and a more detailed stand alone supporting reference document.
Cleco	No	The inclusion of the text implies additional requirements. Keep quidance to a separate paper.
IRC Standards Review Committee	No	This change also requires some additional explanation. What level of importance will be given to such materials? If an SDT inserted a Best Practices document, does that allow auditors to refer to that document for purposes of holding an entity non-compliant? Are these materials there to help entities who do not know how to comply? If these materials are self-help guides, then it would be better to include them as URL references that are stored in the NERC library. That way there can be not confusion about whether the material is there as a self-help guide, or as a reference for auditors.
FRCC Manager of Operations	No	We agree that this is valuable information and important to convey with the standard. This should be a separate companion document balloted, approved and posted with the standard but not be a part of the standard.
TO/TOP	No	We agree that this is valuable information and important to convey with the standard. This should be a separate companion document balloted, approved and posted with the standard but not as part of the standard.
SERC OC Standards Review Group	No	We recommend that the text “grid reliability” be substituted for “Bulk Electric System” on page 6 of the draft.The inclusion of non-mandatory guidelines in a standard that will ultimately be approved by FERC gives undue credence to “guidelines” that will lead undoubtedly to mis-application by future compliance auditors. We suggest separation of this information from the mandatory reliability standard that will be filed at FERC. It could be held in a repository on the NERC website.
Arizona Public Service Company	Yes	
Central Maine Power, Iberdrola	Yes	

Organization	Yes or No	Question 8 Comment
USA		
Consumers Energy	Yes	
Duke Energy	Yes	
Exelon	Yes	
Manitoba Hydro	Yes	
North Carolina EMC	Yes	
Omaha Public Power District	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	
Tennessee Valley Authority	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	
Tampa Electric Company	Yes	Aids in improved understanding of FAC-003-2.
FirstEnergy	Yes	Although we agree that guidelines are good to have and agree that having them in the body of the standards is convenient, we question how this section will be viewed from a compliance standpoint. We understand this section is not intended to be mandatory, but does that mean that regulatory authorities will only approve the other sections of the standard and not this section? Also, it should be clear and explicitly stated in the lead-in

Organization	Yes or No	Question 8 Comment
		to this section that this is guidance which is not mandatory and enforceable. Additionally, terms such as "shall", "should", and "require" should not be used in the guidance section because the information presented in this section could be construed as mandatory by an auditor. An example of this is in the guidance information for Requirement R7 which states "Documentation is required when the annual work plan is adjusted...". This mandatory-type language should not be included in the Guidelines section.
MRO's NERC Standards Review Subcommittee	Yes	Another good addition to the standard and will help clarify parts of the standard without referring to another document or set of guidelines.
Southern California Edison Company	Yes	Assuming that the "Guideline and Technical Basis Section" will be retained and revised in future revisions to the standard, such information should prove very useful.
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	BGE agrees with the addition of a Guidance & Technical Basis section.
JEA	Yes	Having the information in the same document makes the information more accessible to the entity attempting to comply with the standard.
Ga Transmission Corp	Yes	I do however believe that each utility should have the flexibility to manage there program the way they feel is the most effective method. I do not want the technical basis section to limit options. Should this be in a white paper format?
East Kentucky Power Cooperative, Inc.	Yes	I have no preference one way or the other on this issue.
ITC Holding	Yes	ITC agrees with Guidelines and Technical Basis section, but recommend including useful Technical Reference actions and activities that would support defense-in-depth strategy. We also feel that to avoid any confusion with the applicability section and interpretations in the future, any references to the Bulk Electric System in the standard sections and guidance/technical reference document should be reviewed and changed.
Entergy Services	Yes	Language should be added to the Guideline and Technical Basis Section to clarify or re-state that this section is for assisting entities in understanding how to comply with the standard but does not contain mandatory actions/activities, and a statement that entities are not required to use the information in the Guideline and Technical Basis Section.

Organization	Yes or No	Question 8 Comment
Western Area Power Administrtaion	Yes	The format could be enhanced by moving the "Guidelines and Technical Basis" section forward to be included with the corresponding Requirement, Measure, and Rationale. Perhaps the "Guidelines and Technical Basis" could also be combined with the corresponding "Rationale" text box. This would be helpful because it is awkward flipping back and forth between these two sections when trying to fully understand a requirement.
NERC Staff (12 staff members)	Yes	There is no language in the body of the standard to clarify that the information in the Guideline and Technical Basis Section of the standard is not subject to enforcement. We suggest revising the heading to “Application Guidelines.” This is the term that was originally proposed by the Results-based team and is the heading identified in the proposed Standard Processes Manual.
SERC Vegetation Management Sub-committee	Yes	This format adds clarity and improves readability.
Xcel Energy	Yes	This is all good information to add a depth of understanding for the user. It's not clear as to how modifications to the Guideline and Technical Basis would come about - it is the same as the standards revision process? Does this section replace the white paper? Will it actually be deemed to be part of the Standard? We are curious as to the legal weight if this is not part of the Standard and believe that key provisions are in this section. It seems it should be part of the Standard.
Ameren	Yes	This is helpful information to have that does not clutter up the requirements and measurements. Under R6, the third paragraph, there is a typo: ..."230kv transmission lines at least once 'line' during the calendar year".
City of Tallahassee (TAL)	Yes	This is very useful information and will minimize misinterpretations by the entities and the compliance teams.
Progress Energy Carolinas	Yes	This new section provides additional information and SDT rationale that is critical to understanding how to comply with the requirements in the standard and will also provide SDT intent/basis for the interpretation process when necessary. Progress Energy believes that any references to the Bulk Electric System in the standard sections and guidance/technical reference document should be reviewed and changed (e.g. “grid reliability”) to avoid confusion with the applicability section in this draft and avoid the potential for applicability interpretations once this version is adopted.
Independent Electricity System Operator	Yes	This section should be placed in an appendix preceded by a statement that clearly states the purpose of the Section and indicates that the Guideline and Technical Basis Section does not in any way add to the requirements of the standard. Also, this section appears to be a summary of the Technical Reference Document but we could find no reference to the Technical Reference within the standard. This reference should be cited for the benefit of anyone seeking further detail.

Organization	Yes or No	Question 8 Comment
Western Area Power Administration - Upper Great Plains Region	Yes	WAPA - UGPR agrees with the concept of placing the background technical information in a separate section. We were a bit concerned with the Guideline for R7 because it seems to mandate many more items than were called for in the actual requirement in the body of the standard. Our belief is that the Guideline section should not infer or list any more requirements than the actual requirement dictates.
Ad Hoc Group subteam formed to review draft standard	Yes	We agree with the additional material as an aide to entities to further understand the basis for the requirements. In this spirit the information should support compliant behavior and thus the reliability objectives of the standard.
Dominion	Yes	While we agree that these can be useful, we are concerned about the 'last minute' change (March 24th) to the technical reference document being used by those reviewing the materials for this project.
Southen Company	Yes	Would it be better to have an official white paper associated with the standard rather than having this information in the standard? A white paper can be changed without seeking industry comments and approval from NERC, while information in the standard must go through the entire approval process. As it is structured now, information-only updates to the Technical Basis Section would require the entire standards approval process to be completed.
American Electric Power (AEP)	Yes	Yes, although American Electric Power does question whether auditors will be able to avoid reading and applying such text.
KCPL	No	I like information that helps to "guide" and "provide guidance", however, we already having trouble with information from FAQ's, White Papers, and other guiding documents creeping into the requirements by auditing teams. The inclusion of "guiding information" in the text of the Standard itself may promote adding to requirements. Although helpful, I recommend removing this text from within the body of the Standard.

9. Do you prefer putting URL links to reference materials in the Guideline and Technical Basis Section, or do you prefer putting the additional technical/information materials in appendices, where needed, to supplement the Guideline and Technical Basis Sections? Please explain.

Summary Consideration: Out of the 52 comment forms received, 28 forms indicated a preference for use of URLs, 22 indicated a preference for appendices and 5 indicated no preference. These results indicate that either approach would be acceptable. The SCPS agreed to put the information in an appendix rather than in a URL because it is difficult to maintain the accuracy of URLs over time, and because keeping the information in the body of the standard is less work for end users as all information would be in one place.

Organization	Yes or No	Question 9 Comment
MRO's NERC Standards Review Subcommittee		If there is background information contained in a URL link pertaining to a particular Requirement, that link should be with the Requirement that it pertains to.
Ad Hoc Group subteam formed to review draft standard		Judicious and correct use of citations should allow the proper documentation of references without the hazard of expired URLs or expansion from using appendices.
Tennessee Valley Authority		No preference, either way will work.
Consumers Energy	Prefer appendices	
Exelon	Prefer appendices	
PPL Electric Utilities Corporation (NCR00884)	Prefer appendices	
South Carolina Electric and Gas	Prefer appendices	
TO/TOP	Prefer appendices	
Tucson Electric Power Co.	Prefer appendices	
Western Area Power Administrtaion	Prefer appendices	

Organization	Yes or No	Question 9 Comment
Xcel Energy	Prefer appendices	
GCPD	Prefer appendices	Actually we prefer that they are separate from the standard entirely. See question 8.
Cleco	Prefer appendices	An appendix ensures the information is available and original at the time the document it supports was prepared.
ERCOT ISO	Prefer appendices	An Appendix would probably be easier to use, but either type of reference would suffice. Regardless of which is used, it should include a footnote that the information is “For Information Purposes Only” and are not a part of the Standard’s Requirements. If the information causes confusion, then it should be eliminated completely. Also, what types of materials are contemplated to be “reference materials”?
Oncor Electric Delivery	Prefer appendices	Appendices would memorialize documents vs URL links to reference materials that may change over time. This Standard was crafted from “todays” point of view and background information. Reference material might change and the URL would point to material not validating the current form, logic, and background of the Standard.
Entergy Services	Prefer appendices	Appendices, or reference to a single site for all referenced material, would be the most helpful from the standpoint of keeping the information together and more readily available.
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Prefer appendices	BGE prefers that such materials be included in the appendices.
NERC Staff (12 staff members)	Prefer appendices	It is not clear what part of the standard is being balloted and what part is not. In addition, it is not clear what process will be used to modify the guideline/technical basis section of the standard. This needs to be determined before this standard can be balloted.
FRCC Manager of Operations	Prefer appendices	Links can get broken - official records (ie. standards) need to stand alone.
City of Tallahassee (TAL)	Prefer appendices	The fewer places I have to navigate to the better I like it. I find too many “broken” URLs. This will also make it easier when I download a “complete set” of standards from the NERC website.
Dominion	Prefer appendices	Unless a ‘failsafe’ process is developed to insure URL links are keep up-to-date, preference is to locate all referenced materials within the standard (same URL). However, there are a number of ways that

Organization	Yes or No	Question 9 Comment
		URL linkage could be done. One would be to locate all Guideline and Technical Basis documents on a webpage dedicated to such documents. This would allow URL linkage at a higher level than if there is URL linkage for each Guideline or Technical Basis document. This is probably the easiest to maintain. Another would be to link each Guideline or Technical Basis document referenced in a standard to the same URL as that standard. Maintaining URL linkage is probably medium. Yet another is to have the URL link to a webpage created specifically for that Guideline or Technical Basis document. This is likely to be the hardest (require most effort) to maintain.
CenterPoint Energy	Prefer appendices	URL links tend to change over time due to administrative requirements. Moving them to the appendix will avoid revisions to the Standard. See also answer to Q3 regarding the Guideline and Technical Basis Section.
Florida Municipal Power Agency (FMPA) and Some Members	Prefer appendices	URLs can break
Nebraska Public Power District	Prefer appendices	URLs change periodically.
North Carolina EMC	Prefer appendices	Will need to put something in place to make sure that the links get properly updated if they change.
Ameren	Prefer the inclusion of URL links	
Arizona Public Service Company	Prefer the inclusion of URL links	
Bonneville Power Administration	Prefer the inclusion of URL links	
Consolidated Edison Company of New York, Inc.	Prefer the inclusion of URL links	
Duke Energy	Prefer the inclusion of URL links	
Ga Transmission Corp	Prefer the inclusion	

Organization	Yes or No	Question 9 Comment
	of URL links	
IRC Standards Review Committee	Prefer the inclusion of URL links	
Manitoba Hydro	Prefer the inclusion of URL links	
Omaha Public Power District	Prefer the inclusion of URL links	
Pepco Holdings, Inc. - Affiliates	Prefer the inclusion of URL links	
Southern California Edison Company	Prefer the inclusion of URL links	
Utility Risk Management Corporation	Prefer the inclusion of URL links	
Progress Energy Carolinas	Prefer the inclusion of URL links	Additional reference documents provide additional information that may be needed to understand how to comply and the basis of requirements, but they should not be included as appendices. The use appendices could result in a SDT process/effort for minor revisions to the reference document.
American Transmission Company	Prefer the inclusion of URL links	Also see ATC's comment on "Guideline and Technical Basis Section" in Question #3 above.
Independent Electricity System Operator	Prefer the inclusion of URL links	In general the additional reference materials may make the document extremely voluminous so we prefer URL links.
Northeast Power Coordinating Council	Prefer the inclusion of URL links	Links are preferable to alleviate the concerns expressed in question 8 above, especially with respect to FERC approval.
JEA	Prefer the inclusion of URL links	No strong preference.

Organization	Yes or No	Question 9 Comment
Tampa Electric Company	Prefer the inclusion of URL links	None
Western Area Power Administration - Upper Great Plains Region	Prefer the inclusion of URL links	None
Orange and Rockland Utilities, Inc.	Prefer the inclusion of URL links	Prefer the inclusion of URL links
East Kentucky Power Cooperative, Inc.	Prefer the inclusion of URL links	Provides for clarity and readability.
Southen Company	Prefer the inclusion of URL links	See answer to number 8.
American Electric Power (AEP)	Prefer the inclusion of URL links	The use of URL links is probably most appropriate for an increasingly web-based reference repository.
SERC OC Standards Review Group	Prefer the inclusion of URL links	This format adds clarity and improves readability.
SERC Vegetation Management Sub-committee	Prefer the inclusion of URL links	This format adds clarity and improves readability.
ITC Holding	Prefer the inclusion of URL links	URL links provide immediate access, are less cumbersome, and usually provide additional research material when accessed.
FirstEnergy	Prefer the inclusion of URL links	We prefer URL links. Although, we are not clear what this question is asking regarding "additional technical/information materials". Is the team referring to "supplemental" reference documents such as the technical reference white paper that was recently posted for stakeholder review on March 24, 2010? If so, we agree that supplemental reference material be included through URL links, perhaps at the end of the "Guidelines and Technical Basis" section of the standard.
KCPL	Prefer appendices	Although a good idea generally, too many times URL links change name or something else that makes the imbedded link unusable or takes you to the wrong place. Having an appendix ensures the

Organization	Yes or No	Question 9 Comment
		information is available and original at the time the document it supports was prepared.

10. Do you agree with the addition of the Background Section to allow provision of background information, and to elaborate on the reliability-related drivers for the standard/change? Please explain.

Summary Consideration: Most of the comment forms (42 out of 54) indicate agreement with the addition of the Background Section.

Some commenters expressed similar concerns as those for Text Boxes and the Guideline and Technical Basis Section that the information should not be subject to FERC's review and approval, and that the Background may contain Requirement material that is enforceable. Other commenters suggested that this Section is not needed given the addition of the Guideline and Technical Basis Section.

The SCPS believes that the Background Section serves a different purpose than the Guideline and Technical Basis Section. The Background Section provides the background that led to the development of the standard, tying it to the reliability drivers and principles. In essence, the Background Section gives readers the reasons for and the events that led to the development of the standard. The Guideline and Technical Basis Section serves a very different purpose as it provides readers with the technical background, general guidelines, and general practices or technical merits that the responsible entities could take or consider to help them meet the reliability requirements. The Guideline and Technical Basis Section can also be used to provide some examples to illustrate the coverage or intent of the requirements.

On this basis, the SCPS believes it is in the interest of the majority of commenters to keep the Background Section. The SCPS will communicate to the standard drafting team that the Background Section must not contain requirement material, and should not include any technical information that should be provided in the Guideline and Technical Basis Section. The Background Section will remain at the front of the standard. As noted in response to other questions, a legal statement will be added to clarify which sections of the standard are mandatory and enforceable.

Organization	Yes or No	Question 10 Comment
ERCOT ISO	No	Again, it is preferable to include this type of information in an Appendix as long as it is made clear that this is additional information and is not a part of the Standard's Requirements. However, if there is a chance that the additional information included in the Appendix is going to cloud the Requirements spelled out in the Standard, then our preference is to eliminate the additional information completely.
SERC OC Standards Review Group	No	Inclusion of a background section in a document that will be approved wholly by FERC give undue credence and weight to statements which may be included that are not necessarily factual 100% of the time. For example, the first sentence of the last paragraph of the background section reads as follows: "Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating." Obviously, woody stems do not grow during the dormant season, yet the background asserts that it does. There are other areas in this sentence that are not completely factual and should not be in a reliability standard. We recommend that the text "grid reliability" be substituted for "Bulk Electric System" on page 6 of the draft.
Consumers Energy	No	Not necessary.

Organization	Yes or No	Question 10 Comment
Northeast Power Coordinating Council	No	NPCC participating members believe this is more informational and appropriate on the individual standard’s NERC Website “Under Development” page, in an announcement, cover letter, or to be distributed with the standard drafts.
Nebraska Public Power District	No	Same as item 7.
CenterPoint Energy	No	See answer to Q3.
Florida Municipal Power Agency (FMPA) and Some Members	No	The background belongs in the Guidelines and not as part of the standard.
FRCC Manager of Operations	No	The background section should be re-named "Technical Basis". Trim content and leave only the first and last paragraphs. In addition, all 5 paragraphs of the section as written should be moved to the front of the Guidelines and Technical Basis document as a "Background" section of that separate document. NERC should limit its use of "background" information within the reliability standard itself.
TO/TOP	No	The background section should be re-named "Technical Basis". Trim content and leave only the first and last paragraphs. In addition, all 5 paragraphs of the section as written should be moved to the front of the Guidelines and Technical Basis document as a "Background" section. NERC should limit its use of "background" information in reliability standards.
Cleco	No	The inclusion of the text implies additional requirements. Keep quidance to a separate paper.
Exelon	No	This information should be in appendices or reference documents available on the NERC standards site.
Ameren	Yes	
Arizona Public Service Company	Yes	
Bonneville Power Administration	Yes	
Central Maine Power, Iberdrola USA	Yes	
City of Tallahassee (TAL)	Yes	

Organization	Yes or No	Question 10 Comment
Duke Energy	Yes	
East Kentucky Power Cooperative, Inc.	Yes	
Ga Transmission Corp	Yes	
JEA	Yes	
Manitoba Hydro	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
North Carolina EMC	Yes	
Omaha Public Power District	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	
Southen Company	Yes	
Tennessee Valley Authority	Yes	
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	

Organization	Yes or No	Question 10 Comment
Western Area Power Administrtaion	Yes	
SERC Vegetation Management Sub-committee	Yes	Allows for a more informed interpretation of the standard.
American Electric Power (AEP)	Yes	American Electric Power agrees with this change.
American Transmission Company	Yes	ATC agrees that the Background Section is helpful; however, NERC should define its purpose and goal. What is currently written is more than necessary to be included in this standard.
Dominion	Yes	Dominion agrees but suggests it be moved towards end (suggest between Administrative and Guideline/Technical basis sections).
Ad Hoc Group subteam formed to review draft standard	Yes	Great help in showing intent and reliability goal of the standard.
Southern California Edison Company	Yes	Including a background section should prove useful for future editions. However, at some point such information could be made accessible through URL links.
ITC Holding	Yes	ITC agrees with the addition of Background Section
GCPD	Yes	May help in iterpretations and in explaining to stakeholders in our organizations.
Tampa Electric Company	Yes	None
Western Area Power Administration - Upper Great Plains Region	Yes	None
Progress Energy Carolinas	Yes	Progress Energy agrees and believes that the background section will allow relevant background information that provided direction/guidance for the SDT to be readily available after the standard revision is adopted.
Entergy Services	Yes	The Background Section is helpful, but the last sentence states....."Thus, this Standard's emphasis is on vegetation grow-ins.". This statement seems to conflict with the outage Category 2 "Fall In" classification,

Organization	Yes or No	Question 10 Comment
		even though it is a fall in from within the ROW.
Xcel Energy	Yes	The Background section should be moved to the back, in front of the Guideline and Technical Basis.
IRC Standards Review Committee	Yes	This background is important for insertion at the beginning of a SAR. But for a standard-posting, it is suggested that this section is redundant and better inserted after the requirement and measures with the other Administrative materials.
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	This makes sense to BGE.
NERC Staff (12 staff members)	Yes	This provides a context for the requirements and is very beneficial in understanding the intent of the standard.
Independent Electricity System Operator	Yes	This section expands on the purpose statement and will promote a uniform understanding of the fundamental drivers for the standard and its requirements, as well as its philosophy and scope.
Consolidated Edison Company of New York, Inc.	Yes	We agree but believe the Background Section should be situated before the Applicability Section in the revised Standard and redundant verbiage should be removed.
Orange and Rockland Utilities, Inc.	Yes	We agree but believe the Background Section should be situated before the Applicability Section in the revised Standard and redundant verbiage should be removed.
FirstEnergy	Yes	We agree that a Background section is beneficial. However, we believe it may be more appropriate to move this information to the Guidelines section as a lead-in. Also, we suggest a rewording of the first sentence of the first paragraph on Pg. 2 which states: "Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations". We agree that vegetation can contribute to outages, but it cannot be the sole cause of major outages. Major outages can be prevented if other measures required by other NERC standards are implemented when vegetation causes a line or other equipment to malfunction. We suggest a rewording of this statement as follows: "Interference between vegetation and transmission lines located on many types of land have contributed to significant outages and operational challenges."
KCPL	No	I like information that helps to “guide” and “provide guidance”, however, we already having trouble with information from FAQ’s, White Papers, and other guiding documents creeping into the requirements by auditing teams. The inclusion of “guiding information” in the text of the Standard itself may promote adding to

Organization	Yes or No	Question 10 Comment
		requirements. Although helpful, I recommend removing this text from within the body of the Standard.

11. Do you agree with the addition of an Administrative Procedure Section to place administrative/procedural requirements that are contained in the existing standards but which do not meet the results-based or risk-based criteria? Please explain.

Summary Consideration: Most comment forms (36 out of 52) indicated agreement with this addition.

Some commenters questioned whether or not these Administrative Procedures are mandatory and if so, why they are not placed in the Requirements and Measures Section or at least renamed “Administrative Requirements”. They asked, if the administrative requirements are mandatory, are they subject to compliance audit and if so, would a monetary penalty be applied?

Some suggested that if the administrative procedures are not mandatory requirements, they should not be included in standards and proposed the alternative approach of collecting data/reports through the Rules or Procedure Section 1600.

The intent of creating the Administrative Procedure Section is to separate the procedural and administrative requirements from the results-based reliability requirements since not performing the former tasks does not adversely affect BES control or performance or expose the BES to reliability risks. The SCPS will provide further clarity to the intent of this Section, and consider the use of Rules of Procedure Section 1600 for data/report collection as an alternative.

Organization	Yes or No	Question 11 Comment
Consumers Energy	No	
Nebraska Public Power District	No	Administrative requirements should not be included in the Standard, they may be construed unintentionally as a requirement.
GCPD	No	Anything not directly associated with the compliance requirements or for help with interpretations should not be in the standard.
Northeast Power Coordinating Council	No	As stated earlier, NPCC participating members don’t understand if this section holds sanctionable requirements, and if so under what authority. Administrative items are best left to the ROP or Compliance documents. A results based standard’s primary focus should be on the requirements, and the goal or reliability objective. Taking administrative requirements out of the formal requirements section, adding them to another section, and still deeming them to be requirements is of no value to reducing the administrative burden on the industry. This makes the implementation of the standard more burdensome due to the fact that these additional “requirements” now reside in different places in the standard document. NPCC participating members suggest if these are truly valid requirements they need to be together with the other requirements. If they do not meet the results based criteria, and were included in this “Administrative Procedure” section strictly because of that, then they need to reside in another document. Their continued appearance in the document dilutes the integrity of the results based standard initiative.

Organization	Yes or No	Question 11 Comment
Exelon	No	Exelon is concerned this will raise questions concerning what criterion separates an administrative requirement from a results or risk based requirement. How are administrative requirements to be treated in the CMEP?
CenterPoint Energy	No	It is not clear if the Administrative Procedure is a mandatory activity. It would be helpful if the intent of this section was stated within the Standard.Also, this section in not parallel with the Rating and Rated Electrical Operating Conditions exception contained in R1 and R2. We recommend the following parallel wording for the first paragraph of this section:"The Transmission Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying certain Sustained Outages of the categories defined below, while operating within the Rating and Rated Electrical Operating Conditions, determined by the Transmission Owner to have been caused by vegetation that includes, as a minimum, the following:"Also, the categories listed in this section do not have parallel language to M1 and M2. We recommend that this section should adopt the wording in M1 and M2 for the Sustained Outages to be reported. Currently, Category 2 and Category 4 do not distinguish between an IROL and Major WECC Transfer Path. This may become a tracking problem since they have different Violation Risk Factors. If this is not important, then Category 1A and 1B can be combined.
Consolidated Edison Company of New York, Inc.	No	It is somewhat confusing to have sanctionable requirements located in other sections of the Standard outside of 'Requirements and Measures.' The section title 'Administrative Procedure' is somewhat misleading; if it was renamed 'Administrative Requirements' we feel it would be clearer to the industry.
Orange and Rockland Utilities, Inc.	No	It is somewhat confusing to have sanctionable requirements located in other sections of the Standard outside of 'Requirements and Measures.' The section title 'Administrative Procedure' is somewhat misleading; if it was renamed 'Administrative Requirements' we feel it would be clearer to the industry.
SERC OC Standards Review Group	No	Reporting Outages is not a part of Vegetation Mgmt. Therefore, this reporting belongs in an Administrative Section or possibly via a NERC 1600 request. In no circumstance should it be a Requirement of the standard. In the last paragraph this section appears to place a requirement on a regional reliability entity: "The Regional Entity will report the outage information provided by Transmission Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages." Was this really intended? What if the RE fails to make a report?
IRC Standards Review Committee	No	Some additional explanation is needed. If the requirement is to do inspections, and compliance is measured on that basis only then the Administrative Section is OK. If the entity is mandated to also meet the actions specified in the Administrative Section, then the change is not acceptable. This standard's example administrative section is introducing new requirements into the standard, and those requirements should be in the standard. In short, if there is a reliability requirement than that is what should be mandated.

Organization	Yes or No	Question 11 Comment
		The idea of mandating administrative items that are often designed to make auditing (not operations or planning) simpler should not be mandated.
FRCC Manager of Operations	No	The "Administrative" section needs to be streamlined - remove the first 2 paragraphs - quarterly reporting is no longer required and would be an administratively redundant process to the self-reporting of outages. Leave the outage categories to support consistent self-reports. Delete last paragraph - reporting by the Regional Entities to NERC is a delegated function that should be governed by the delegation agreements, rules of procedure or other internal ERO process, not within a reliability standard since REs and the EROs are not users, operators, etc of the BPS.
TO/TOP	No	The "Administrative" section needs to be streamlined - remove the first 2 paragraphs - quarterly reporting is no longer required and would be an administratively redundant process to the self-reporting of outages. Leave the outage categories to support consistent self-reports. Delete last paragraph - reporting by the Regional Entities to NERC is a delegated function that should be governed by the delgation agreements, rules of procedure or other internal ERO process, not a reliability standard.
Ad Hoc Group subteam formed to review draft standard	No	The administrative procedure section is appropriate under results-based requirements. However, we believe that reporting requirements established under other methods, such as the CMEP, may be confused by including it. It is unclear how non-conformance with administrative procedures would be handled. Perhaps administrative procedures would be better handled under ROP Section 1600 data requests or other Rules.
Cleco	No	The inclusion of the text implies additional requirements. Keep quidance to a separate paper.
Florida Municipal Power Agency (FMPA) and Some Members	No	The reporting requirements really boil down to a self-reporting or self-certification process since the only items to report would be violations to the standard. If such quarterly reporting is desired, it is really a self-certification process and should be governed by that process and not through a separate Administrative Procedure.FMPA recommends deleting the last paragraph - reporting by the Regional Entities to NERC is a delegated function that should be governed by the delegation agreements, rules of procedure or other internal ERO process, not within a reliability standard since REs and the EROs are not users, operators, etc of the BPS, and are not designated in the Applicability section.
Ameren	Yes	
Arizona Public Service Company	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 11 Comment
Central Maine Power, Iberdrola USA	Yes	
City of Tallahassee (TAL)	Yes	
Dominion	Yes	
Entergy Services	Yes	
Ga Transmission Corp	Yes	
Manitoba Hydro	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
NERC Staff (12 staff members)	Yes	
Omaha Public Power District	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
PPL Electric Utilities Corporation (NCR00884)	Yes	
South Carolina Electric and Gas	Yes	
Southen Company	Yes	
Southern California Edison Company	Yes	
Tennessee Valley Authority	Yes	

Organization	Yes or No	Question 11 Comment
Tucson Electric Power Co.	Yes	
Utility Risk Management Corporation	Yes	
Xcel Energy	Yes	Are we to understand that the requirements listed in the Administrative section are not sanctionable from a NERC compliance perspective?
American Transmission Company	Yes	ATC feels this adds good will on the part of the entity to submit necessary reports, however, ATC requests clarification whether this section is subject to NERC violations. (Currently not listed in Table 1 Time Horizons, VRFs and VSLs)
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	BGE agrees with addition of an Administrative Procedure section.
Duke Energy	Yes	During the WEBINAR, a question was raised regarding how failure to meet an Administrative/Procedural requirement would be addressed by the Regional Entity. Can the Standard Drafting Team prepare a response to the question?
JEA	Yes	However, it needs to be made clear whether this is subject to audit, and whether failure to meet the requirement is subject to the same or different enforcement procedures as the numbered requirements in the standard.
East Kentucky Power Cooperative, Inc.	Yes	I do not believe that reporting of outages is a part of development and implementation of a Vegetation Management Plan. I fail to see how it brings value to the standard.
ITC Holding	Yes	ITC agrees that the “administrative role” such as outage reporting; shouldn’t be a reliability requirement and are more appropriately defined as an administrative procedure. We would also like some clarification on whether this section of the standard is subject to NERC violations. Currently it’s not listed in Table 1 Time Horizons, VRFs and VSLs
Western Area Power Administration - Upper Great Plains Region	Yes	None

Organization	Yes or No	Question 11 Comment
Tampa Electric Company	Yes	Not sure why separating 1.A & 1.B is preferred over 1,2,3,4?
Progress Energy Carolinas	Yes	Progress Energy agrees that “Administrative” functions such as outage reporting should not be listed as a reliability requirement and are more appropriately defined as an administrative procedure. (Outage reporting is an administrative function that does not directly improve reliability which should be the focus of reliability standard requirements.)NERC has other formal information request procedures in place (such as a NERC 1600 request), if that becomes necessary to ensure outage reporting.
SERC Vegetation Management Sub-committee	Yes	Reporting Outages is not a part of Vegetation Mgmt. Therefore, this reporting belongs in an Administrative Section or possibly via a NERC 1600 request. In no circumstance should it be a Requirement of the standard.
Western Area Power Administrtaion	Yes	The Administrative Procedure section could be moved forward following the Background section to better introduce the general administrative overview for what would then become the following Requirements, Measures, etc. These general administrative and procedural requirements are more easily overlooked when they included at the back of the Standard.
American Electric Power (AEP)	Yes	This addition is acceptable
Independent Electricity System Operator	Yes	This section imposes an additional reporting requirement but there is no associated VRF or VSL. Is this intentional? How will failure to report on time be treated? This is unclear as is the significance of any such Administrative “Requirements” within the standard, in general. Is the intention to establish separate procedures to govern the administrative and reporting obligations of registered entities under the Rules of Procedure?
FirstEnergy	Yes	We agree with the Administrative Procedure Section. Monetary fines should not be imposed for noncompliance with administrative requirements.
KCPL	No	It is too easy to unintentionally infer or introduce something that is not intended to be a requirement, but gets interpreted as a requirement in this section. Standards should be clear in what is a requirement and what is helpful information. If these are requirements, then propose them as requirements. If not, then remove to another guiding document.

12. Is there any other information that should be included in the standard document? If so, please explain why you feel that this information should be included.

Summary Consideration: None of the commenters offered any suggestions for including additional information that has not already been suggested in one or more of the comments provided in Questions 3 to 11.

Some commenters provided comments on the standard content itself.

Some commenters commented on the “Informal Comment” process. While this process may be useful in speeding up the process of developing standards, it introduces a potential for a given Team to ignore valuable comments (either because the issue is unknown to them, or because the proposal does not agree with the team’s ideas). They suggested that all comments (both formal and informal) be posted immediately for all to review. The SCPS agrees with the suggestion however the software currently used to collect stakeholder feedback doesn’t format the data collected in a manner that is easy to understand. NERC staff is exploring alternatives that would make it easier for stakeholders to view comments as they are submitted. The informal commenting process is meant to collect industry views in the same manner as the formal commenting process; it differs only in not requiring the SDTs to provide a response to each comment. Notwithstanding this provision, the SDT is still obligated to post all comments and provide summary responses to the comments.

Organization	Yes or No	Question 12 Comment
Ad Hoc Group subteam formed to review draft standard	No	
American Transmission Company	No	
Bonneville Power Administration	No	
City of Tallahassee (TAL)	No	
Cleco	No	
Consolidated Edison Company of New York, Inc.	No	
Consumers Energy	No	
Dominion	No	

Organization	Yes or No	Question 12 Comment
Duke Energy	No	
East Kentucky Power Cooperative, Inc.	No	
Exelon	No	
Florida Municipal Power Agency (FMPA) and Some Members	No	
Ga Transmission Corp	No	
Independent Electricity System Operator	No	
ITC Holding	No	
JEA	No	
Manitoba Hydro	No	
Nebraska Public Power District	No	
NERC Staff (12 staff members)	No	
Northeast Power Coordinating Council	No	
Oncor Electric Delivery	No	
Orange and Rockland Utilities, Inc.	No	
Pepco Holdings, Inc. - Affiliates	No	

Organization	Yes or No	Question 12 Comment
PPL Electric Utilities Corporation (NCR00884)	No	
South Carolina Electric and Gas	No	
Southern California Edison Company	No	
Tennessee Valley Authority	No	
Tucson Electric Power Co.	No	
Utility Risk Management Corporation	No	
Western Area Power Administrtaion	No	
Tampa Electric Company	No	All areas have been addressed and clarified as needed.
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	No	BGE feels no other information is necessary for inclusion.
American Electric Power (AEP)	No	None
Western Area Power Administration - Upper Great Plains Region	No	None
GCPD	No	Too much already.
Omaha Public Power District	Yes	
SERC OC Standards Review	Yes	As suggested in comment six, an improvement would be also listing the applicable table rows with each requirement which consolidates all pertinent info with the requirement. Also, adding the penalty matrix would

Organization	Yes or No	Question 12 Comment
Group		facilitate discussions with property owners/agencies resisting maintenance activates. This standard indicates a lack of recognition that vegetation outages are not necessarily reliability events. In the quest for improved reliability, spending the money necessary to achieve perfect compliance with R2, as stated, either will increase customer rates unnecessarily or cause the misallocation of maintenance funding away from maintenance activities that have a substantially higher impact on reliability.
SERC Vegetation Management Sub-committee	Yes	As suggested in comment six, an improvement would be also listing the applicable table rows with each requirement which consolidates all pertinent info with the requirement. Also, adding the penalty matrix would facilitate discussions with property owners/agencies resisting maintenance activates.
Arizona Public Service Company	Yes	Clearance 1 needs to be put back into this requirement as written. This is a vegetation management standard and there needs to be clear direction on how the system is going to be maintain at the time of maintenance. This ensures a clear direction to the utility the system has to be maintained. ANSI A-300 part 1 and 7 needs to be a requirement within the standard. Following this consensus agreement within the Professional Utility Vegetation Management sector outlines a process for providing a reliable transmission system. At a minimum ANSI A-300 part 1 and 7 should be incorporated into the Guideline and Technical Basis Section as a resource for compliance with this standard. Prudence would dictate that it be adopted into this draft as the foundation of any transmission vegetation management program as it is the accepted standard for professionals who are responsible for managing vegetation for electric utilities.Personnel qualifications need to be included in the standard and should include minimum measures such that there is consistency across the industry. This ensures that personnel are qualified and will have ongoing training and education in utility vegetation management. For example: The person who manages the field operation should have at least 5 years experience in vegetation management be an International Society of Arboriculture Certified Arborist and a Utility Specialist.
Ameren	Yes	In 4.3.1, suggest that "ice" be included in circumstances beyond the reasonable control of a TO in addition to the other "acts of God".
Entergy Services	Yes	More clarifying language throughout the document would be helpful.
Progress Energy Carolinas	Yes	None, other than the comment about potential improvements in question #6.
IRC Standards Review Committee	Yes	Regarding the new format, the idea of using "Informal Comment Periods" may be useful in speeding up the process of developing standards, but it also introduces a potential for a given Team to ignore valuable comments (either because the issue is unknown to them, or because the issue does not agree with their ideas). How will the Standards Committee or others ensure the quality of the process does not suffer in this way? What type of review process is contemplated to detect such behavior? Having the Formal

Organization	Yes or No	Question 12 Comment
		comments at the end of the process may prevent subject matter experts (SME) from seeing the comments and perspectives of other SMEs. The SRC suggests that all comments (both formal and informal) be posted immediately for all to review.
Xcel Energy	Yes	See comments to #1, #7 and #13 of this form
FirstEnergy	Yes	See our other comments.
Central Maine Power, Iberdrola USA	Yes	Table 2 expand footnote - State that table 2 is intended as a buiding block to develop clearance at time of vegetation management work. See TVMP for clearances.
CenterPoint Energy	Yes	The detailed rationale for the required one year inspection cycle in R6 should be included in the Technical Reference. The explanation provided in the Rationale that it “seems to be reasonable” and in the Technical Reference that it is “reasonable based on upon average growth rates across North America and common utility practice” are unfounded and arbitrary without a specific reference to a North American study. The Technical Reference should contain an example diagram of “the portion of the ROW where the corridor edge zones are designated by regulatory bodies for vegetation to exist” taken from the examples in the Definition of Terms Used in Standard section. It is unclear how this example should be interpreted for compliance should a Sustained Outage occur from vegetation growing within this zone. It is common for regulatory bodies to push utilities to plant trees or maintain trees within transmission rights of way to “hide the lines”, and it is unclear if this example is attempting to encourage such practice by regulatory bodies at the sacrifice of reliability.In general, the Technical Reference should contain more specific examples of violations of the Requirements and highlight specific exceptions related to vegetation related outages.The background and basis for adding the term “Active Transmission Line Right-of-Way” should be added to the Technical Reference.The background and basis for 4.2.4 that excludes the Standard from applying to fenced substations should be added to the Technical Reference.Just as the force majeure statement (4.3.1) was moved to the Applicability section of the Standard, the exception for applicability beyond the Rating and Rated Electrical Operating Conditions should be included in the Applicability section as well. Currently, it is only included in R1 and R2. It should be made clear if the other Requirements and Measurements must consider conditions beyond the Rating and Rated Electrical Operating Condition.Within the Requirements and Measures section there should be subheadings for each type of Requirement, performance-based, risk based, and competency-based. This classification is only indicated in the Technical Reference.
MRO's NERC Standards Review Subcommittee	Yes	The NSRS believes a section for definitions and abbreviated terms such as, Active ROW, MVCD, and WECC is needed. Also, See comment above in Question 9 on URL links.
Southen Company	Yes	We feel a definition of Category 3 outages (non reportable outages) should be included under the

Organization	Yes or No	Question 12 Comment
		administrative procedures. Although these outages are not reportable, this would provide a mechanism for classifying these outages so the utility can maintain evidence of its investigation and the rationale for not reporting them.
KCPL	No	

13. Do you have any other comment regarding the draft FAC-003-2 Transmission Vegetation Management standard that have not been addressed above? If yes, please provide a reference to the section, requirement, or subrequirement that you believe should be changed, added or deleted and the rationale for your proposal.

Summary Consideration:

1. **Reasonable control** - Some commenters expressed that the phrase "reasonable control" is difficult to enforce, while others wanted it moved to another section of the standard.
   The term "reasonable control" is prevalent in many force majeure clauses. It intends to limit the extent of compliance responsibility to those conditions that are within the sphere of the TO's ability. The SDT have determined that eliminating the word "reasonable" would not detract from the original intent and have made the change to the standard.
   The SDT does not have a preference for the location of the force majeure language. This is within the scope of the Standards Committee Process subcommittee to address.

2. **Differentiate between "human error" versus "human activity" –** Some commenters requested further explanation of these terms.
   The SDT intended for the term "human activity" to be used in the Background section of the standard and have removed "human error". The SDT intends the phrase human activity to describe those human actions that are outside the control of the Transmission Owner such as logging, vehicle contact with tree, removal or digging of vegetation, horticultural or agricultural or arboricultural activity. The SDT proposes the following new Force Majeure text:

   "This Standard does not apply to any occurrence, non-occurrence, or other set of circumstances that are beyond the control of a Transmission Owner subject to this reliability standard, including acts of God, flood, drought, earthquake, major storms, fire, hurricane, tornado, landslides, ice storms, vehicle contact with tree, human activity involving, removal of vegetation, installation of vegetation or digging around vegetation, animals severing trees, lightning, epidemic, strike, war, riot, civil disturbance, sabotage, vandalism, terrorism, wind shear, or fresh gales (or higher) that restricts or prevents performance to comply with this reliability standard's requirements. Nothing in this section should be construed to limit the Transmission Owner's right to exercise its full legal rights on the Active Transmission Line ROW."

3. **Competency-based requirement R3**: Some commenters expressed that R3 is deficient in detail.

   The SDT determined that the following parameters demonstrate competency:

   - Understands the dynamics of conductor movement over its operating range and design conditions, understands the inter-relationship between growth rates and inspection frequency and choice growth control method. And successfully implements the understanding as evidenced by lack of vegetation related outages.
   - Conducts inspections on a frequency that accounts for vegetation growth rates and local conditions.
   - Considers scheduling and permit lead times.
   - Designs work plans that levelizes work load.
   - Utilizes best industry practices such as ANSI A300.
   - Develops vegetation maintenance plans that account for vegetation growth rates and local conditions.
   - Incorporates a feedback mechanism in the program.

- Balancing ROW management with cost and science.
- Establishes wire security zones.
- Documents non-compatible species.
- Exercises full legal rights on the Active Transmission Line ROW to avoid outages.
- Knows the condition of its ROW.
- Gives clear direction to field personnel so that they know what to do to maintain the clearances.
- Addresses an interim corrective action plan.

The SDT proposes the following modification to R3:

*"**R3.** Each TO shall document the procedures, processes, or specifications it uses to prevent the encroachment of vegetation into the MVCD. Such documentation will incorporate the dynamics of a transmission line conductor's movement throughout its Rating and Rated Electrical Operating Conditions and the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the Transmission Owner's applicable lines."*

4. **Flexible annual work plan** – Some commenter indicated that the word "flexible" in requirement R7 is difficult to enforce without more detail.

The SDT modified the requirement as follows:

*"**R7.** Each Transmission Owner shall complete an annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made provided they do not put the transmission system at risk."*

5. **The SDT revised Section 4.2.2 –** The SDT did not agree to the removal of the reference to FAC-014 and have re-inserted it.

*"**4.2.2.** Overhead transmission lines operated below 200kV having been identified as an element of an Interconnection Reliability Operating Limit (IROL) designated in compliance with NERC Standard FAC-014."*

6. **Reporting –** Some commenters recommend keeping the outage reporting language in the technical requirements section.

The Standards Committee Process Subcommittee is the appropriate body to address this issue.

7. **Gallet distances** – Some commenters asked how can reliability be equal or better when Gallet distances are less than IEEE distances.

At the Gallet distance, the probability of Flashover is zero. The current in-force version of the FERC Transmission Vegetation Management Program Standard (FAC-003-1) uses the minimum air insulation distance (MAID) without tools formula provided in IEEE Std. 516-2003 to compute the required minimum vegetation clearance distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

The current in-force version of FAC-003-01 allowed the TO's to use either Table 5 or Table 7 to establish the absolute lowest value for these minimum clearance distances. Table 5 could be used if the TO knew the maximum transient over-voltage factor for its system. Otherwise, Table 7 would have to be used. Table 7 represented minimum air insulation distances under the worst possible case transient over-voltage factor. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

The SDT sought out a different method of establishing these absolute minimum clearance distances that considers both the outside weather environment and also the realistic maximum transient over-voltages factors for in service transmission lines.

In general, the worst case transient over-voltages occur on a transmission line when the line is open on one end and is opened on the other and then inadvertently re-energized when trapped charge is present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case scenarios mentioned above can be ignored.

For the purposes of FAC-003, the worst case transient over-voltage then becomes the maximum value that can occur with the line energized. Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service AC line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without a pre-insertion device (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. 362 kV), the maximum transient over-voltage of an "in-service" ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 242 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equation is a proven method of computing the required strike distances for proper transmission line insulation coordination. These equations were developed for both wet and dry applications and can be used with any value of transient over-voltage factor.

When one compares the Minimum Air Insulation Distances using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes using identical transient over-voltage factors it is clear that the Gallet equations yield a more conservative (larger) minimum distance value.

The following table is an example of this comparison:

Comparison of spark-over distances computed using Gallet wet equations

vs.

IEEE 516-2003 MAID distances using realistic transient over-voltage factors

(AC) Nom System Voltage (kV)	(AC) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	IEEE 516 MAID (ft) @ Alt. 3000 feet
765	800	1.4	8.89	8.65
500	550	1.4	5.65	4.92
345	362	1.4	3.52	3.13
230	242	2.0	3.35	2.8
115	121	2.0	1.6	1.4

8. **Definition of Active Transmission Line ROW –** Some commenters indicated that the Active Transmission Line ROW definition is unclear.

The SDT thoughtfully considered FERC staff's concern regarding the Active Transmission Line Right-of-Way. However, in light of the Commission direction in Order 693, in response to First Energy's concern about unnecessary expense of managing unused rights-of-way, to include such a provision, the SDT was left with only two practical choices, the current proposed definition or a fill-in-the-blank site-specific TO-designated approach. Acknowledging the desire to eliminate fill-in-the-blank requirements, the SDT opted for the proposed definition. Therefore, the SDT respectfully suggests that no workable change can be made to this definition and still implements Commission direction and thus has opted to retain the current draft language.

9. **R4: "Responsible control center" and "verified knowledge"** – Some commenters remarked that there is no "Local Control Center" entity in Functional Model and that could be an enforcement issue. Other commenters sought clarification for the phrase "verified knowledge".

The SDT clarified R4, M4 and Rationale text box:

*“**R4.** Each Transmission Owner shall notify the responsible control center without undue delay when qualified personnel confirm the existence of a vegetation imminent threat. A vegetation imminent threat condition is one which is likely to cause a Fault at any moment.”*

*“**M4.** Each Transmission Owner that has experienced a confirmed vegetation imminent threat will have evidence that it notified the responsible control center.”*

*“**Rationale***

To ensure rapid notification of the correct personnel when an occurrence of a critical situation is observed. Qualified personnel may include line workers and utility arborists. The responsible control center is selected to ensure that the flow of operational information, which includes broken cross-arms and tree issues, will continue to the Transmission Operator (or its delegate).”

10. **R6 and R7** – Several commenters noted that R6 and R7 were assigned High VRFs although they previously were Medium.

SDT changed R6 and R7 from High to Medium. The justification is provided by NERC VRF Worksheet Tool and review of NERC VRF Guideline. (See attached VRF_Tool_R6.pdf and VRF_Tool_R7.pdf documents for the VM SDT consensus response utilizing the VRF Tool.)

11. **Requirements R1 and R2** – some commenters stated:

i. The MVCD requirements R1 and R2 need more detail to be enforceable and auditable. They do not see how FAC-003-2 addresses sag and sway with the elimination of Clearance 1.

ii. Concern that the VRF for lines covered in R2 is a Medium.

Consideration:

i. The SDT understands the commenter’s concern. The SDT worked on addressing the concern by drafting alternate language to be responsive to issues of enforceability and auditability and offer the following as an alternative R1/R2 for industry comment:

*“**R1.** Each Transmission Owner shall manage the floor of its Active Transmission Line ROW in accordance to one of the following at all times:*

A) A fixed maximum vegetation height of 15 feet from the ground at the mid-half of the span and 20 feet in the outside quarters of the span, or,

B) A calculated maximum vegetation height that is the sum of the minimum conductor height at “max sag” plus MVCD plus cycle growth, or,

C) A calculated minimum vegetation to conductor clearance that is the sum of “max sag” in the span plus MVCD plus cycle growth, or, *D) A value determined by the Transmission Owner to provide a separation between the conductor and the vegetation that is comparable to options A, B, or C.*

E) Any alternative approach that ensures no encroachment occurs within MVCD, considering the sag and sway of the conductor throughout its operating range under rated conditions.

F) A value to provide a separation between the conductor and the vegetation that is the sum of MVCD, and a value that considers the sag and sway of the conductor throughout its operating range under rated conditions plus 10 feet."

NOTE: The SDT suggests similar language as found in the posted draft for measures M1/M2 may be appropriate with this alternate R1/R2.

ii. The SDT considered the comments that pertain to the assignment of a Medium VRF to R2 on the basis of IROL/Major WECC Transfer Path designation. The SDT determined that the assignment of Medium is justified because the loss of non-IROL or non-Major WECC Transfer Path lines pose a lower reliability risk than those lines that are elements of an IROL or Major WECC Transfer Path.

Organization	Yes or No	Question 13 Comment
American Electric Power (AEP)		American Electric Power suggests replacing the term "Minimum Vegetation Clearance Distance" with "Critical Vegetation Clearance Distance." The use of "minimum" suggests that the minimum is acceptable. However, in dealing with landowners or land managers, we may not be able to negotiate any more than the minimum. "Critical" would help convey the sense that the distance borders on dangerous unacceptability.
Central Maine Power, Iberdrola USA	No	
Consumers Energy	No	
East Kentucky Power Cooperative, Inc.	No	
IRC Standards Review Committee	No	
Manitoba Hydro	No	
Pepco Holdings, Inc. -	No	

Organization	Yes or No	Question 13 Comment
Affiliates		
PPL Electric Utilities Corporation (NCR00884)	No	
South Carolina Electric and Gas	No	
Southern California Edison Company	No	
Tennessee Valley Authority	No	
Tucson Electric Power Co.	No	
Tampa Electric Company	No	None
FRCC Manager of Operations	Yes	- Applicability Section 4.3 - use the term "Exemptions" instead of "Other" as it is more descriptive.- As noted earlier - Applicability Section 5 - use the term "Technical Basis" instead of "Background" and streamline by removing paragraphs 2, 3 and 4.- R
American Transmission Company	Yes	(a) R1 and R2 (pg.7) - What is meant by “to avoid a Sustained Outage”. Could be argued that a grow-in that does not cause a Sustained Outage is acceptable. (Could this be a FERC issue?)(b) R5 (pg.9) - ATC believes the term “temporarily” should be stricken from the requirement. This leaves too much to interpretation and does not add to the requirement(c) R6 (pg.9) - The descriptive timeframe “at least once per calendar year” is used. What does this mean? Every 365 days or a 12 month period within a calendar year? NERC needs to define this.(d) R4 (pg.15 in the Guideline and Technical Basis) - The term “verified knowledge” is used which does not seem consistent with the definition of “Verified Knowledge” in R4 Rationale on pg.8.(e) R4 (pg.16 in the Guideline and Technical Basis) - The term “responsible control center” is used and further defined. ATC believes this is the Transmission Operator. This should either be moved to the “Definitions of Terms” section or to R4 of the standard where the term is used.
Western Area Power Administrtaion	Yes	1) It is suggested that the word "located" in the third bullet in Measure 1 and Measure 2 be replaced with the word "originating". As worded, M1 or M2 could be interpreted to mean that vegetation originating outside of the right-of-way which blows or sways into contact with conductors “located inside the ... right-of-way” would be evidence of a violation of R1 or R2. Utilities generally are very limited in their ability to manage vegetative conditions outside of their right-of-

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		ways.2) Please reference the comments under Question 2 above regarding the incompleteness of requirements R3 and R7 in fully replacing the CCZ management concepts utilized in the Draft 1 version of the proposed FAC-003-2.3) The requirement R4 Guidelines and Technical Basis narrative is inconsistent with requirement R4. Specifically, in the Guidelines and Technical Basis section the second paragraph's introductory sentence identifies a requirement for an imminent threat procedure, and the second bullet in this paragraph identifies a need to identify vegetation related conditions that warrant a response. Neither of these items are a requirement of R4 as currently written. R4 only speaks to the notification of the responsible control center when it has verified knowledge of a vegetation imminent threat condition.4) The requirement R7 Guidelines and Technical Basis section is written with an inappropriate bias towards very extensive or time based vegetation maintenance programs. Comments received from previous draft standard reviews have revealed that there are many other effective program approaches being utilized by the industry. It is suggested that this section be revised to broaden its scope to incorporate these other program approaches.
Ga Transmission Corp	Yes	1) I would like further examples of inactive portions of corridors. For example would a ten foot buffer strip that is in addition to a normal width to stay off a property line but is included in an easement plat but not cleared be considered inactive corridor or not? 2) The MVCD definition may not be realistic in its wording. Many utility companies may not be able to maintain these clearances at "design of Transmission Facility". This needs further definition maybe "NESC moderate wind". Many utilities in coastal areas will design lines for high sustained winds due to hurricanes these clearances may not be possible to maintain under these conditions however the line may be designed to with stand these winds.
FirstEnergy	Yes	1. Requirements R1 and R2 - We do not agree with the "zero tolerance" for real-time observation of encroachments that do not cause an outage. When discovered, most Transmission Owners (TO) take immediate action to alleviate encroachments and it is not appropriate to be fined for taking immediate action when no outage has occurred. Therefore, a violation should only occur when the TO has not immediately alleviated the situation within 24 hours. We suggest the following change to the first bullet in Measures M1 and M2: "Real-time observation of encroachment into the MVCD that is not corrected within 24 hours."2. Measurement M1 and M2 - For additional clarity, we suggest adding the following wording from Guideline and Technical Basis into M1 and M2 - "Brief encroachment by falling vegetation are not considered a violation."3. Requirement R4 - Since the intent of this requirement is the immediate notification of an imminent threat, we suggest adding the word "immediately" between "shall" and "notify".4. Requirement R5 - We suggest removing the term "temporarily" in the requirement. Some constraints faced by Transmission Owners are permanent and appropriate alternate action is permanently implemented. 5. Requirement R7 - Although we agree that the TO should be allowed to adjust the plan, the use of the term "flexible" is subjective. Additionally, the phrase "to ensure no vegetation encroachments occur within the MVCD" is redundant with the other requirements of the standard. Therefore, we suggest revising the wording of Requirement R7 to the following: "Each Transmission Owner shall implement an annual vegetation work plan. Adjustments to the work plan to defer work beyond the calendar year are acceptable and shall be documented."6. Coordination between Project 2007-07 and 2010-07 - Since the TO-GO interface team has identified the need for Generator Owner (GO) applicability in the FAC-003 standard, we believe that these two drafting teams should coordinate the addition of the GO into this Version 2 of

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		FAC-003. It would not seem sensible to revise Version 1 of FAC-003 to include the GO while Version 2 is developed and approved without applicability to the GO.7. Compliance Section - Under "Additional Compliance Information", we suggest removing the parenthetical phrase "See Administrative Procedure" and replace with "None". Since the Administrative Procedure is not part of the requirements, it is not sanctionable and should not be included in the Compliance Section.
MRO's NERC Standards Review Subcommittee	Yes	1. Need definition for the phrase “Major WECC Transfer Paths”.2. In question 2 of the comment form, it refers to the “bulk power system.” This standard does not cover the bulk power system, it covers lines above 200kV and certain ones below 200kV.
BGE (on behalf of parent/affiliate companies: CEG, CPSG, CECG, CNE & CENG)	Yes	4.2.4 States that the Standard is not applicable to “...to Facilities .... located inside the fenced area of a switchyard, station or substation”. This implies that anything within the fenced area of a switchyard, substation or power plant does not fall within the jurisdiction of FAC-003-2. Some fenced in areas could be very large and susceptible to vegetation encroachments issues.4.3.1 Suggest including in the Force Majeure government a phrase referencing government interference, such as “Federal, State or other regulatory interference, including legal or other legislative actions, that prevents performance to comply with this reliability standard.”M1 & M2 bullet: “Real-time observation of encroachment into the MVCD” implies that real-time observation of vegetation encroachment ensures reliable operation the Bulk Electric System. The reliability standard objective states;”To improve the reliability of the electric Transmission system by preventing those vegetation related outages that could lead to Cascading.”However, real time observation of current operating conditions provides no assurance that vegetation will not lead to outages. BGE recommends removing the language. If an inspector finds vegetation encroaching into the MVCD during a visual inspection he / she should immediately initiate an Immediate Threat Notification. Therefore, this measure has no value.Disagree with R6. - Inspection Frequency. Very prescriptive. Please consider allowing TO’s to select an annual frequency that best fits their requirements, such as calendar year, every growing season, every non-growing season, etc. BGE currently defines their inspection frequency as annually during the non-growing season, October 1 to May 1. BGE believes inspecting during the dormant season is a best practice due to the ability of the inspector to identify vegetation defects, especially off the ROW, which could be hidden during the growing season due to foliage, canopy cover, etc. Also, if a utility elects to leverage an advance technology, such as LiDAR, it provides the most effective results when LiDAR is utilize during the growing season, therefore allowing the results of the advance technology to enhance the fall to spring inspection cycle. All of the above comments are submitted on behalf of: - Baltimore Gas & Electric Company - Constellation Energy Group, Inc. - Constellation Power Source Generation, Inc. - Constellation Energy Commodities Group, Inc. - Constellation New Energy, Inc. - Constellation Energy Nuclear Group, Inc.
Arizona Public Service Company	Yes	APS objects to number 3 Objectives statement. This is the only reliability standard that has at its Objective to prevent vegetation related outages that could lead to cascading. This is a reliability standard and its objective needs to be: “To improve the electric Transmission system by preventing vegetation related outages.” Requirement 6: To ensure reliability the TO’s are responsible for doing an annual inspection. You either do it or don’t and if you don’t finish it you should be held accountable. There shouldn’t be a lower VSL because you didn’t finish all of it. This is poor

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		planning on the utilities part.Requirement R7: When developing the annual work plan the Transmission Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Transmission Owners may also need to consider those special landowner requirements as documented in easement instruments. There needs to be parameters for the TO to show they allowed time for procedural requirements. An example, some land agencies will give you permission to perform work in as little time as two weeks and others can take two years. Even within the same land agency the timing of approvals is a moving target. APS recommends the TO must show documentation it submitted their Vegetation Management Plan to the land agency at least 120 days prior to the required start date. If the land agency doesn't respond within this time frame and the utility can not perform the work they shouldn't be held responsible.
JEA	Yes	Generally, I believe this document is a huge improvement. The requirements are much clearer and easier to implement than some versions from the past. I do not understand why R7 is still in this standard however. It appears to be a requirement whose purpose is only to dictate HOW an entity must document its implementation of its vegetation management program. Thus, I believe this requirement should be removed.
Consolidated Edison Company of New York, Inc.	Yes	In R5, the SDT should better define the phrase 'where a transmission line is put at potential risk due to the constraint.' This is rather vague and could lead to inconsistent practices between utilities. Con Edison defines all undesirable species on the full width of the ROW as 'potential risks to the transmission line' regardless of height or location at the time of vegetation management. Interim corrective action should only be required when the potential risk is approaching the imminent threat classification.
Orange and Rockland Utilities, Inc.	Yes	In R5, the SDT should better define the phrase 'where a transmission line is put at potential risk due to the constraint.' This is rather vague and could lead to inconsistent practices between utilities. ORU defines all undesirable species on the full width of the ROW as 'potential risks to the transmission line' regardless of height or location at the time of vegetation management. Interim corrective action should only be required when the potential risk is approaching the imminent threat classification.
Florida Municipal Power Agency (FMPA) and Some Members	Yes	In the Applicability section, the use of the term "Other" should be changed to another term, such as Force Majeure, since its purpose is not to include scope into the standard, but exclude scope from the standard.R4 uses the term "responsible control center", which seems inappropriate. Consider using the term "responsible operating entity". The M4 is simply a restatement of R4 without an example of types of evidence, e.g., such as voice recording, operator logs, etc.R5, consider using a different term than "constrained", which has other transmission related connotations. Possibly "limited" or "hindered".FMPA disagrees with a 3 year retention schedule for all of the Requirements and Measures. R4 and M4 would seem to be supported by operator logs, voice recordings and such and three year retention for such evidence is inconsistent with other standards.

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ITC Holding	Yes	In the previous draft the VRF's R6 and R7 were listed as Medium; and in the latest revision they are listed as High VRF's, what is the reason for this change or is this just a mistake?"Temporarily" should be removed from the requirement (R5 pg.9) this will be an interpretation issue and doesn't add to the requirement.
Northeast Power Coordinating Council	Yes	NPCC participating members recognize the hard work the drafting team has done and appreciate the efforts to address the issues presented. An issue seems to be a recurring theme with the advent of the MVCD. Some believe that the eventual adoption of this standard with MVCD will result in the reduction of current trimming cycles and clearance distances. Opinions have been expressed that this may result in increased vegetation contacts and trips. After reviewing some of the MVCD distances, for example 3.12 feet at sea level for 345kV, some expressed the opinion that this is much less than what typical trim practices are today, and may actually "lower" the bar for trimming practices, and effectively allow a TO to trim less and reduce the margin of clearance.Requirement R1 discusses encroachment. M1 bullet 1 states one way to violate encroachment would be:"Real-time observation of encroachment into the MVCD..."From a practical standpoint what is meant here? Who would determine this and how would it be done? The intent is certainly to avoid a sustained outage. However, if a TO was in the process of trimming after an active growing season, and noticed a slight encroachment while trimming, would it be considered a reportable violation? How would the RE measure compliance with avoiding something, with the absence of a sustained outage reported? A statement should be added to the "Definition of Terms Used in Standard" section to indicate how terms defined in the NERC Glossary and used in the standard are identified (for example capitalizing the first letters of the term or using italics or bold font). To avoid confusion when a term might be used at the beginning of a sentence, bolding or italicizing the term should be considered. The Guideline and Technical Basis section should be a separate document, and not part of the standard (mentioned previously in question 8). It should be included in the Technical Reference Document.Applicability 4.2.4--A fenced area of a switchyard, station or substation can have vegetation that could present a potential risk to facilities. What is the reason for this exclusion, and the exclusion in Applicability Section 5--Background paragraph 3 "...this Standard does not apply...to line sections inside an electric station boundary."Referring to our previous responses to questions 1 and 2 for Requirements R1, R2, and R3, what rating is used? It is possible to operate above a facility's normal rating for a prescribed time (for example a transmission line may be operated above its normal rating but below its LTE rating for up to 4 hours). Operating at emergency ratings should be considered. During emergencies transmission lines might be loaded to their emergency ratings, thus increasing the sag, thus increasing the likelihood of a vegetation caused trip if the required clearances don't take into account the increased loading. Especially in an emergency loading scenario, operating into an avoidable potential risk is very undesirable. Referring to FAC-003 - Table 2 - Minimum Vegetation Clearance Distances (MVCD), for 345kV (line to line), 3.12 foot (assuming to ground) clearance is required at sea level. IEEE Std 516-2003 IEEE Guide for Maintenance Methods on Energized Power Lines dated July 29, 2003, Table 5 (p. 20), lists the MAID (minimum air insulation distance) for 345kV phase to phase equipment at altitudes below 900 meters (2953 feet) to be 2.88 meters (9.45 feet) phase to ground. It is understood that MAID is "The shortest distance in air between an energized electrical apparatus and/or a line worker's body at different potential...", but the clearance differences at the various voltage levels seem very significant. If a figure is referenced in a requirement (R3), it would be preferable to have

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		that figure positioned within that requirement. If that is not possible, it should be explicitly stated where the figure can be found. Requirement R5--Legal actions and other events that prevent vegetation maintenance work be included in the Introduction Section 4.3.1. What does “interim corrective action” mean specifically? The requirement as written needs to be made clearer. Without the Rationale box it loses its meaning (refer to the question 3 response).Interim Corrective Actions are explained on page 28 of the separate Technical Reference Document, with examples such as modifying the inspection interval, or limiting the loading on the line (effectively changing its rating) to minimize sag. “Interim corrective action” should be defined and added to the Glossary.Are voltages referred to in the Standard (Applicability Section) line to line or line to ground for ac systems? (345kV line to line is 199kV line to ground, below the 200kV threshold in the standard). Are the voltages also applicable to DC equipment?
Xcel Energy	Yes	On page 6, in paragraph 5 ("Background"), we suggest enhancing the 3rd paragraph by inserting the words "Active Transmission Right-of-Way", as follows: "...addresses vegetation management in the Active Transmission Right-of-Way along applicable overhead lines..." This change emphasizes that this does not apply to areas outside of the Active Transmission Right-of-Way. Comments to Requirments and Measures Section (pages 7 -9)The term Minimum Vegetation Clearance Distance (MVCD) should be explicitly defined as a new "definition" rather than explained in a "rationale" box. Additionally, formalizing the definition would give weight to how "Table 2" is supposed to be used. As it is currently drafted, the requirements of the standard don't refer to Table 2 at all. (i.e., - our understanding is that the rationale boxes are for clarification and the requirements should be able to convey what is necessary on their own.)MVCD - while we understand this as an 'engineering term', the terminology is difficult to convey since land owners tend to question the need to do anything more than the "minimum". We recommend revising the term to "Critical Clearance Distance (CCD)". M1 & M2 should be revised to insert the concept of "verified knowledge" (that is used in R4). This is because M1 & M2 do not clarify whose real-time obseration it is referencing. As such, we recommend stating "Real time verified knowledge of encroachement into the MVCD..." instead of just the term "observation" to make it clear that a trained, knowledgeable individual is making this determination. Also, it may make sense to turn "verified knowledge" into a defined term since it will be used in M1, M2 and R4. If it is not made a defined term, then the meaning in M1 & M2 must be clarified in those sections (maybe a cross refefrence to as defined in R4 and on page 15 will work). However, we think it is best to make it a defined term.R5: Rationale box: consider enhancing the second sentence by adding the word "significant", to read "...avoid significant risk..."R5: Requirement & Measure: consider adding exception language when the constraint is known to be longer than "temporary". e.g. - stand offs can occur on right of ways that cross federal and tribal lands and the entity cannot force the federal government to do do something.R6: Xcel Energy still believes the requirement in R6 that mandates an annual inspection is too onerous and is at odds with the results-based approach of these revisions. Xcel Energy urges the retention of the provision in the existing standard that allows the Transmission Owner to set the frequency of inspection. In some areas of the country, annual inspections may not be adequate. Yet in other areas, a longer inspection frequency may be perfectly reasonable and practical. Our point is that inspection frequency should not be treated as if it were “one size fits all”. If treated this way, we feel this could pose a risk to reliability and is not likely to be cost-effective. The Transmission Owner should be allowed some flexibility. However, if the drafting team disagrees and determines that an annual inspection is to be mandated, Xcel Energy believes that an exception to the

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		annual inspection is appropriate when a non-subjective advanced technology such as LIDAR is utilized to achieve actual clearance distances. This places the Transmission Owner in a situation where it can rationally determine that the objectively measured distances result in a situation where an inspection need not be performed within the next year. It is suggested that R6 be revised to read as follows: Each Transmission Owner shall perform a Vegetation Inspection of all applicable transmission lines at least once per calendar year, unless the Transmission Owner, based on a non-subjective advanced technology, such as LIDAR, determines that a longer inspection period is appropriate.R7: Revise the requirement to eliminate the superfulous language at the end of the sentence that says "... to ensure no vegetation encoachments occur wihtin the MVCD", i.e., R7 would read as "Each Transmission Owner shall execute a flexible annual vegetation work plan."
Independent Electricity System Operator	Yes	Our comments to this point have focussed exclusively on the proof-of-concept for using the results-based criteria for developing a reliability standard. We have one comment on the specifics of Requirement R7 and its Measure M7. The rationale for M7 states that a flexible annual vegetation work plan allows for work to be deferred into the following calendar year provided it does not have the potential to become an imminent threat. This will evidently require some kind of assessment in each case. Will entities be expected to document those assessments as evidence in support of its view that the associated vegetation did not have the potential to become an imminent threat, or would it be sufficient to look at the outcomes of these decisions to defer items in the work plan - i.e. there were no imminent threats and sustained outages? Finally, we applaud the drafting team for its efforts in developing this draft. The industry has often commented about overly prescriptive requirements and I believe this draft has focused on the “what” of the requirements and left the “how” up to the appropriate entities. In our view this draft, with its succinctly stated requirements, represents an important first step in the right direction. Thank you.
Ameren	Yes	Page 9, M7 - what are the limits of flexibility in executing "a flexible annual vegetation work plan"?
Duke Energy	Yes	Please review the VRF Guideline because we believe that the VRF’s for R6 and R7 should possibly be changed to “Medium” instead of “High”. They were “Medium” in the last draft of FAC-003-2.
Westchester County Board of Legislators	Yes	Please see e-mail sent to sar@nerc.com. Thank you.
Progress Energy Carolinas	Yes	Progress Energy believes that the VRFs for R6 and R7 should be returned to “medium” since no singular “risk-based” requirement in a defense in depth strategy should be depended upon to eliminate/prevent risk to grid reliability. In a defense in depth strategy, no one specific “risk-based” or “competency” requirement should be “high” unless failure to complete that singular requirement will result in an immediate “high” risk to grid reliability (if that is the case, then the standard is not truly employing a defense in depth approach). Also, R6 and R7 (which have a zero tolerance) have no differentiation between grid impacting facilities (IROL) and facilities primary impacting local customer reliability (i.e., radial lines to load, etc).

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North Carolina EMC	Yes	R4: The requirement to notify the responsible control center of an imminent threat may potentially result in confusion at the control center if the transmission lines in question are not part of the control center's actively monitored grid. As an example, NCEMC has a few short radial 230kV lines that fall under the requirements of this standard, but these lines are not shown on the BA's control center system because they are downstream from a protective device located at a tap off networked transmission lines. A vegetation-related outage on these lines would not result in any of the transmission elements continuously monitored by the control center being outaged, and the operator receiving a call notifying the imminent threat may not have any familiarity with the line section being identified, since it is not on their system. If prompt action to respond to any imminent threat is the intended goal, why not consider making it a significant part of the mitigating factors of an actual outage.
City of Tallahassee (TAL)	Yes	Recommend deleting the “to avoid a Sustained Outage” in R1 and R2. Has a violation occurred if a momentary (successful reclose) outage occurs but the TO did not “observe(s) vegetation within the” MVCD? While it may not have to be reported on the quarterly report, Table 1 for the Lower VSL seems to suggest a violation of the MVCD has occurred, even if it was not “observed” as “required” in the Guideline and Technical Basis.In the Guideline and Technical Basis, the final paragraph for R1 and R2, line 3 contains an extra word “...encroachment is not be a violation...”In the Guideline and Technical Basis, the third paragraph for R6, line 2/3 contains an extra word “...230kV transmission at least once line during the calendar year.”
Cleco	Yes	Requirement 4:Recommend the SDT consider modifying to make it clear the requirement applies to threats within the right of way (ROW).Requirement 4.3.1:Recommend adding human activities to the list of causes. Logging activities are listed but other human activities such as private property owner tree care operations are not.
Exelon	Yes	See R6. Exelon prefers “annual” to “calendar” but notes the requirement runs counter to the results based approach and could be interpreted to be inconsistent with R7.The Rationale for R6 is ambiguous and without justification suggests shorter but not longer cycles are acceptable. If local factors can shorten a cycle, they could also increase it. The Rational is in conflict with the prescriptive nature of the requirement.
NERC Staff (12 staff members)	Yes	Standard Development TimelineThe Development Steps Completed section of the standard is incomplete. This section should include the dates of previous postings. Draft 1 of revised standard was posted for stakeholder comment from 10/27/08 - 11/25/08. Draft 2 of revised standard was posted for stakeholder comment from 09/10/09 - 10/24/09.Definitions of Terms Used in StandardThe definition of Active Transmission Right-of-Way is ambiguous and subject to interpretation. This definition need to be revised to add clarity. It is unclear what “active transmission facilities” are. In the gray box, the SDT should explain what “active portions of corridors” are, and how that is different than the “land that is occupied by active transmission facilities.” The terminology should be consistent. The example should state whether the width is the portion that has been cleared or should be cleared and if it was not maintained and should have been. The SDT should explain the reference to the National Electrical Safety Code in the gray box, and how it differs from the IEEE clearances. In addition, the team should explain why the Table 2 clearances set forth

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		in the standard itself are not referenced. The examples in the “inactive portion” suggest that there are active transmission facilities (see references to conductors and circuits). The SDT should provide the rationale for excluded them from vegetation management. While vegetation is permitted to exist at the corridor edge, the SDT should address why there is no obligation to maintain it. The revised definition of Vegetation Inspection does not seem necessary. It appears that the SDT is using the definition to set an expectation for enforcement by adding “which may be combined with a general line inspection.” If both vegetation and general line inspections are to occur concurrently, there should be minimum background requirements to perform such inspections. We recommend that the last portion of the draft definition be moved to the Application Guideline section so the definition of Vegetation Inspection should be “The systematic examination of vegetation conditions on an Active Transmission Line Right of Way.”The team should consider making Minimum Vegetation Clearance Distance a defined term.Effective DatesThe effective date for Ontario needs to be tied to the effective date in the U.S.With respect to the second exception, the team should provide the rationale behind the exception for the effective date for “existing transmission line operated at 200kV or higher that is newly acquired by an asset owner and was not previously subject to this standard”. All existing transmission lines operated at 200 kV or higher are currently subject to vegetation management. Please explain why a new owner would get an exception for this.Based on the wording in the Exceptions section, it appears that some lines in the US could be brought into this standard prior to regulatory approval. (i.e. Lines operated below 200kV, designated by the Planning Coordinator as an element of an IROL or as a Major WECC transfer path, become subject to this standard 12 months after the date the Planning Coordinator or WECC initially designates the lines as being subject to this standard. An existing transmission line operated at 200kV or higher that is newly acquired by an asset owner and was not previously subject to this standard, becomes subject to this standard 12 months after the acquisition date of the line(s))ObjectiveThe purpose of this standard should not be limited to outages that lead to Cascading, but prevention of all vegetation related outagesApplicabilityThis standard should apply to Generation Owners.The term Facilities is defined to exclude those in a fenced area of a switchyard, station or substation. The SDT should provide the basis for the exclusion.Footnote 1 needs to be clarified. It is too cursory.The “Other” section should not be included in this section. It is the expectation that the Compliance Enforcement Authority will not expect the Transmission Owner to prevent tree contacts that the TO could not prevent. This might be better suited in the Application Guideline section.In the “Other” section, the SDT should provide rationale for why the standard is not intended to address “human errors”.The SDT might consider rewording the “Other” section as:”This Standard shall not apply in circumstances where a requirement of this Standard was not complied with due to Acts of God, flood, drought, earthquake, major storms, fire, hurricane, tornado, landslides, logging activities, animals severing trees, lightning, epidemic, strike, war, riot, civil disturbance, sabotage, vandalism, terrorism, wind shear, or fresh gales that restricts or prevents performance to comply with this Reliability Standard's requirements, so long as the non-compliance was not caused by the fault or negligence of the Transmission Owner.”The team should provide justification for the applicability criteria they have selected; specifically why a 200 kV cutoff was chosen.The team should provide justification for eliminating fall-ins from outside the ROW.BackgroundAs a general comment, the background section seems repetitive.The fourth paragraph of the background section notes that this standard is not intended to prevent customer outages due to tree contact with lower voltage distribution systems. It is clear from the applicability section that this pertains to 200 kV and higher, although the standard contemplates that some lower voltage facilities could be subject to the standard. The SDT

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		should address whether this paragraph also address customer outages due to tree contacts with respect to 200 kV or higher facilities.Requirements R1 and R2:R1If an auditor were to assess compliance with R1, they would need to have the list of conductors that were associated with an IROL or a Transfer Path. This list should be identified in the list of evidence that must be retained.R1 & R2 In the Rationale box, the term “a proven transmission design method” is used. Please describe what this refers to, and whether these refer to the IEEE minimum clearances. The SDT should state what the method was and what changes, if any, were made to it.The SDT should address why the requirements only reference line conductors and not transmission facilities or transmission lines (the VSLs refer to transmission lines).The word “encroaching” should be replaced with another word/phrase that clearly defines the concept for compliance purposes. The word, “encroach” could be interpreted differently by different people (how close can vegetation grow before it enters the MVCD and is it a violation of R1/R2 - is it 2”, 2’, 10”, 10’?), whereas the word “enter” is explicit.Guidance is offered in the Guideline section of the standard that implies that all TOs should retain this evidence, yet the evidence is not identified anywhere in the Measures or evidence retention sections of the standard.We suggest adding the phrase, “of its” to clarify that the TO is only responsible for facilities it owns. “In addition, the Transmission Owner should maintain detailed records of the findings of its planned inspections. This documentation constitutes evidence that the Transmission Owner had no encroachments into the MVCD Table distances.”Immediately after the phrase MVCD, we suggest including the text “as specified in FAC-003-2 Transmission Vegetation Management Table 2 - Minimum Vegetation Clearance Distances (MVCD). Table 2 is not referenced in any of the requirements. If you require entities to use the MVCD as stated in Table 2, then this should be referenced in at least R1 and R2.M1 & M2Overall, it appears that these measures are asking for evidence of non-compliance. The initial item under M1 & M2 (shown below) should be rephrased with the addition of the words “verbal or written report of a,” otherwise the measure doesn’t seem as though it could be used objectively. In addition, the words Real-time should be removed, as they ad confusion to the issue.”Verbal or written report of a observation of encroachment into the MVCD, or”The phrase “Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period” should be changed to a footnote that reads “Consider Multiple Sustained Outages on an individual line, if caused by the same vegetation, as one outage regardless of the actual number of outages due to the same piece of vegetation”Momentary outages due to vegetation are also a violation of R1. Momentary outages from tree contacts may not result in a sustained outage but are evidence of a tree within the MVCD. The requirement should not be limited to only sustained outages. Consider this scenario: An entity self-reports a violation of the standard. Does that mean that if there is no actual "real-time observation" or a "Sustained Outage" there is no violation? Who must do the observing? Please explain.Requirement R3 Consider this scenario: A Sustained Outage occurs on a location that was not considered and therefore was not part of the TO’s TVMP. Would this result in a violation simply because the location was not considered when the entity developed a TVMP?Requirement R4 Each requirement should identify “who shall do what under what conditions, for what reliability outcome.” R4 has no identified reliability outcome. What is the reason for making a prompt notification? Is it to give the real-time system operator information on which to develop and implement an action plan if there is an outage on the line with the imminent threat? Then that should be stated in the requirement. R4 contains explanatory information. The sentence “A vegetation imminent threat condition is one which is likely to cause a Sustained Outage at any moment” should be moved to the blue box.Please explain what

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		“verified knowledge” means. The Rationale section does not really address this. While this is in the Guidelines and Technical Basis section, it defines it as “implies reliable confirmation.” This should be clarified and put in the measures section.”Imminent threat” should be defined so that it does not evolve into an enforcement issue.”Notify the responsible control center” should be clarified so that it does not evolve into an enforcement issue.Application Guideline for R4 should contain provisions in the imminent threat procedure for notification of the land owner.M4 should provide examples of acceptable evidence.Requirement R5 This requirement does not include a reliability outcome. The requirement should be rewritten to include a reliability outcome.Requirement R6 The Rationale for R6 is that one year “seems to be reasonable.” The SDT should address how this relates to the practice in place now, and whether it is consistent with current practice or is more or less than current practice. If inconsistent, the SDT should provide an explanation.The Rationale states the TOs should consider other factors that could warrant more frequent inspections. If so, the SDT should explain whether we are requiring them to do so if such factors exist.This requirement does not include a reliability outcome. The requirement should be rewritten to include a reliability outcome.Requirement R7 R7 is ambiguous; it is not clear how this could be enforced objectively. The rationale for the “flexible” plan indicates that the owner can delay work as long as it will not pose an “imminent threat.” The SDT should explain what the Compliance Enforcement Authority would look at to determine that the work that was delayed was not causing an “imminent threat.” The SDT should address whether it would ever be acceptable to delay work on a critical line (covered under R1).In Requirement R7, please explain what “execute a work plan” means. Did the SDT mean implement a work plan? As drafted, it could be read to just have one in place. The SDT should explain what “flexible” means. Does it mean there will never be a FAC-003 violation if you fail to implement the plan? The Rationale says the work can be deferred if it does not have the potential to become an imminent threat. Please explain. Corresponding clarification changes should be made to the VSLs for this requirement.Either M7 or the evidence retention for M7 needs to include the annual work plan. Without that the Compliance Enforcement Authority can’t determine if the plan was executed. The VSLs for R7 imply that the entire annual plan will be accomplished. . . not a “flexible” amount of the plan - the VSLs don’t line up with the use of the word “flexible.”According to the VSL Guidelines the VSLs should be stated in language that identifies the degree of noncompliance in language that identifies the amount that was noncompliant, rather than the amount that was compliant. VSLs for R6 and R7 are stated in terms of the % of the required performance that was compliant and should be rephrased. GuidelinesThe following guidance is offered in the Guideline section of the standard:Documentation or other evidence of the work performed typically consists of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, work inspection reports and walk-through reports.Documentation is required when the annual work plan is adjusted or not completely implemented as originally planned. The reasons for the deferrals or changes and the expected completion date of postponed work should be documented.This implies that all TOs should retain this evidence, yet the evidence is not identified in nearly this level of detain in the Measures section of the standard. In addition, no part of the requirement or measure is clear in indicating that documentation is required to support the need for a work plan adjustment. Evidence Retention The evidence retention periods specified don’t reflect the guidance in the SDT Guidelines. Should the evidence retention be the later of three years or three years from the last audit? The second paragraph should be stricken because it seems to contradict the first paragraph

Organization	Yes or No	Question 13 Comment
		retention period.VSLsThe SDT should verify that the VSLs for Requirement 3 are properly calibrated.Administrative ProcedureThe Administrative Procedure does not require prompt reporting of sustained outages; rather it requires only a quarterly report. This appears to be less stringent than the current requirements as employed today.The SDT should explain what “blowing together” means, and how this is different from a tree that grows into a line.FootnotesFootnote 1 should be deleted or modified. It is only relevant in explaining the proposed modifications to the standard. In footnote 4 the word, “substantially” adds ambiguity.Guideline and Technical BasisIn the Guidelines and Technical Basis section, it states “Requirements 1 and 2 state if the TO observes vegetation within the distances prescribed in FAC-003 - Table 2 it is in violation of this Standard.” This is actually in the Measures 1 and 2 and not the requirements.General commentsThere seems to be a lot of information not captured in the Requirements but rather are in various other sections. The SDT should clearly delineate whether these other sections are considered part of the Standard or just informational.With the next posting of the standard, the drafting team should include the following four points for stakeholder review:1. Justification for selection of the applicable lines. 2. Table listing each FERC directive and stakeholder issue (from the Issues Database) associated with the standard and identification of how the team addressed each of these3. Table listing each VRF and identification of how the proposed VRF meets both NERC criteria for setting VRFs and FERC’s five Guidelines for approving VRFs4. Document identifying how the proposed VSLs meet both NERC criteria for setting VSLs and FERC’s four Guidelines for approving VSLs.There is a significant concern with the use of the Gallet equations in this standard. This standard eliminates Clearances 1 and 2 from the previous version and replaces it with a single Minimum Vegetation Clearance Distance (MVCD) based on the Gallet equations. This approach reflects the most basic lowest common denominator and significantly lowers the bar versus the performance expected from the existing standard. Further, it would not appear that responsible entities would use the Gallet equations as the basis for the development of the vegetation management program. Additionally, whereas the multiple clearance zones provide an indicator of proactive vegetation management, the current proposal does not provide an equivalent demonstration of proactive performance. This approach appears inconsistent with Order 693 and the presentation of NERC standards to provide a defense in depth strategy, which is a fundamental outcome of the results-based standards process. Order 693 states in P24 that the “reliability mandate of Section 215 of the Federal Power Act....contemplates the prevention of incidents, acts, and events that would interfere with the reliable operation of the Bulk Power System.” The SDT should consider adding more clarification to the draft standard and white paper describing the building blocks for determining how much vegetation management (trimming) needs to be performed based upon growth rate of vegetation and the time between trimmings to reflect a proactive approach.The SDT should consider the impact of moving the reporting requirement in the existing standard to the compliance section of the new standard. The team should consider the reporting of this activity on an exception basis within a pre-defined timeframe following the event. This approach would provide more timely awareness to the Regional Entity and NERC of an event than the quarterly reporting expectation, and provide opportunities for identification and implementation of mitigating strategies in a more timely manner. While this approach removes an administrative type requirement from the standard that is believed to provide a deterrent to responsible entities, the increased timeliness of reporting in an exception basis would provide greater benefit to the effort to maintain reliability.Transmission Line is a defined term. The SDT should consider using this term in place of “transmission line.”The report identified in the administrative section of draft 3 of FAC-003 is really a “Periodic Data Submittal” used

Organization	Yes or No	Question 13 Comment
		to assess compliance and does not belong in an administrative section of the standard - it belongs in the compliance section of the standard. "Periodic Data Submittals" is one of eight different compliance monitoring and enforcement processes that may be used to monitor and assess compliance. The eight processes are identified in the Uniform Compliance Monitoring and Enforcement Program of the North American Electric Reliability Corporation and should not be mixed in with other processes or procedures. Each standard must list the appropriate processes in the compliance section of the standard so that there is a clear understanding of the purpose of the data submittal.As drafted, FAC-003-2 applies only to Transmission Owners. It also should apply to Generator Owners. The SDT should explain whether the issues brought forward in the GO/TO Report been considered and are addressed as part of this revision.Please update the mapping document so that it compares the last version of the approved standard to the latest proposed version of the standard so that it is easy to compare the proposed standard to the standard that is in force now.
Utility Risk Management Corporation	Yes	Suggested Improvements to M1. and M2.The purpose of Requirements R1 and R2 is to require the prevention of vegetation encroachments within the MVCD. As made clear in the background and remaining FAC 003-2 requirements, the overarching intent of FAC 003-2 is to prevent sustained outages caused by vegetation that could lead to cascading. However, both M1 and M2 include real-time observations of encroachment into the MVCD as an automatic violation of R1 or R2, respectively (even though the violations may not result in penalty or fine). This is inconsistent with the "defense in depth" goal sought by the committee, as a real time observation using new technologies may in fact demonstrate that the Transmission Owner is in fact aggressively managing vegetation to meet the MVDC requirements and is discovering new encroachments and remediating them quickly and effectively and thereby is not in violation of the standard.Similar to imminent threats, remediation procedures should be permitted for encroachments as well and serve to make clear the observation is not automatically a violation. Classifying a real-time observation of an encroachment automatically as a violation of R1 or R2 penalizes a Transmission Owner for identifying vegetation threats, which are less severe than imminent threats. Under Requirement R4, the transmission owner is permitted to take appropriate actions to alleviate an imminent threat through short term corrective actions upon observation of any vegetation that is near to or is encroaching into the MVCD. (See FAC-003-2 Guideline and Technical Basis, Requirement R4). Considering the allowance for remedial action under Requirement R4 when facing a condition that is "likely to cause a Sustained Outage at any moment," it seems excessive to qualify a real-time observation of an encroachment as a violation of R1 or R2. We suggest a better approach is to modify M1 and M2 to allow for remedial action. Or, in the alternative, the standard should clarify that observations of encroachments using software-enabled technology, such as LIDAR coupled with work order management systems, do not constitute a "real time observation of an encroachment." First, by modifying M1 and M2 to allow for remedial action as suggested below will deal with the concern we raise:M1. Evidence of violation of Requirement R1 is limited to: o Real-time observation of encroachment into the MVCD which is not mediated in accordance with R4. o ... M2. Evidence of violation of Requirement R1 is limited to: o Real-time observation of encroachment into the MVCD which is not mediated in accordance with R4. o ... In the Alternative, "Real-Time Observation" Should be Clarified. As noted above, a real-time observation of an encroachment is evidence of a violation of Requirements R1 and R2. Observations in real time mean "an actual field observation or measurement of the conductor-to-vegetation distance and not a calculated

Organization	Yes or No	Question 13 Comment
		determination of relevant positions." (See FAC-003-2 Guidelines and Technical Basis, Requirements R1 and R2) Given the current definition, it is not clear observations using software-enabled LiDAR would trigger violations and thereby would discourage the Standard's emphasis on preventing sustained outages or Cascading due to grow-ins. This may result in penalties for registered entities that are engaged in good faith activities to prevent sustained outages. The meaning of "real-time observation" should be clarified as to remove any adverse incentives for vegetation inspection and management. To implement this suggestion as an alternative to allowing remediation to prevent an observation from being an automatic violation, the definition could be reworded to state:"Real-time observation" means an actual field observation or measurement of the conductor-to-vegetation distance which is not performed under the regular Vegetation Inspection of Requirement R6 or annual vegetation work plans in accordance with Requirement R7. Such observations do not include calculated determinations of relative vegetation positions. Conclusion:Adopting one or both of these proposed changes would help R1 and R2 measures more fully meet the goal of preventing overgrown vegetation and systemic failures triggered by flash over, as stated in the background section on page 6 of FAC-003-2. The current M1 and M2 use of real-time observations conflicts with the expectation that utilities engage in "defense in depth" measures. As the guidelines conclude regarding Requirements R1 and R2, the Transmission Owner is expected to have a cohesive vegetation management program for managing vegetation in such a manner as to maintain separation between conductors and vegetation. This is to function in conjunction with the imminent threat procedure to facilitate interim corrective action. "However, brief encroachments by falling vegetation are not considered to be a violation." Making the changes suggested above - coupled with the existing requirement that the utility mitigate an observation in accordance with the utility TVMP through a response schedule - thereby advance the goals of the standard and take away an impediment to aggressive defense in depth.
SERC OC Standards Review Group	Yes	The requirements (R6 and R7) for inspections and the performance of work plans are part of a defense-in-depth approach and as such the TO is not depending on singular requirements to prevent sustained outages, therefore, the VRF for R6 and R7 should remain medium not high. We applaud the attempt to improve the readability and ultimate comprehension of reliability standards by changing to this new template. We have included some comments also made by the SERC Vegetation Management Subcommittee (VMS)."The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers."
SERC Vegetation Management Sub-committee	Yes	The requirements (R6 and R7) for inspections and the performance of work plans are part of a defense-in-depth approach and as such the TO is not depending on singular requirements to prevent sustained outages, therefore, the VRF for R6 and R7 should remain medium not high.
GCPD	Yes	The standard should include only R1, R2 and the Clearance Table. Everything else should be in guidelines as to how you might comply with the standard. If R3 thru R7 remain in the standard then it is virtually the same as it exists today, just put in a different order.

Organization	Yes or No	Question 13 Comment
CenterPoint Energy	Yes	The term "Active Transmission Line Right-of-way" (ATLROW) is not defined in sufficient detail in the Definition of Terms Used in the Standard section to know how to apply it to the Requirements and Measures. The Technical Reference merely depicts the relative position of energized conductors, but it does not show a graphical determination of the limits of the ATLROW. The ATLROW is missing a definable and determinable width in its current definition within the Standard which makes it an arbitrary term and does not allow for a clear and measurable expected outcome of each requirement. In several sections, the Standard relies on the specific determination of the physical width of the ATLROW to determine applicability of the requirements. The Vegetation Inspection definition refers to “on” an ATLROW. The Background section refers to “outside” the ATLROW. Table 1 refers to “within” and “on” the ATLROW. M1 and M2 refer to “inside” the ATLROW. R3 and M3 refer to “on” the ATLROW. The Administrative Procedure refers to “inside and/or outside” and “within” the ATLROW. The Guideline and Technical Basis section refers to “on or near” the ATLROW and the “limited” ATLROW “width”. It also says that, “The Transmission Owner should, therefore, endeavor to maintain its ATLROW to the full extent of its legal rights at all times in all cases.” Since the Standard does not currently define how a Transmission Owner is to determine the specific boundaries of the ATLROW, it would appear that the Transmission Owner is to make that determination on a case by case basis at its discretion. Should that not be the intent, we recommend the definition for the ATLROW to be, “A strip or corridor of land or aerial space that is occupied by energized transmission conductors with its operational clearance limits defined by the Transmission Owner’s specific legal rights but in no case less confining than the MVCD applied to the movement of the conductors within their Rating and Rated Electrical Operating Conditions.” This definition contains sufficient detail to determine the physical limits of the ATLROW, and it allows for vegetation management to apply within the full extent of the legal rights of the Transmission Owner while requiring a minimum area for vegetation management in undefined ROW’s to ensure Sustained Outages are minimized.M1 contains a reference to “real-time observation of encroachment into the MVCD” but does not explain who is to make the observation and where it is to be documented. If this is to be done by the Transmission Owner, then perhaps it should be a Measurement under R6 and recorded under M6.The language in R6 refers to inspecting “transmission lines” and Table 1 for R6 refers to inspecting “ROW”. Both areas should use consistent terminology.M1 and M2 have the potential for double jeopardy when a Sustained Outage occurs because the Violation Severity Level has an entry for an MVCD encroachment (which causes the outage) and another sister entry for the type of Sustained Outage. Some additional clarity in the application of M1 and M2 is necessary.R5 should include the exception stated in the Rationale text box to add clarity to the Requirement. R5 should read, “Each Transmission Owner shall take interim corrective action when it is temporarily constrained from performing planned vegetation work, where a transmission line is put at potential risk due to a constraint, except where the risk is avoided by implementing an alternate work methodology.” In the Guideline and Technical Basis section for R1 and R2 (page 15), there is a reference to records of “planned inspections” and “evidence” for no encroachment into the MVCD. This reference should be moved to R6 where the inspections are required. If R6 is intended to provide evidence for M1, then that should be stated in R6.In the Guideline and Technical Basis section for R6, the reference to the VSL calculation units and the example units should be consistent-the example should use “line miles”, not just “miles”.Table 2 contains several “*” in the voltage column that are not defined.In the Technical Reference on page 21, the following sentence should be deleted, “If constraints cannot be

Organization	Yes or No	Question 13 Comment
		overcome and if design clearances are sufficient, an exception to the Transmission Owner's 10-foot guideline might be made." The Technical Reference should not provide examples of granting exceptions as they may be misinterpreted as an endorsement by NERC to increase the planting of trees near and under transmission lines without taking into account several other factors such as ROW access, changing design conditions, future line additions and rebuilds. The inclusion of modifications to the wire zone on page 24 regarding the wire-border zone model should be re-examined to be sure they are specific to an environmental conservancy requirement while allowing for construction and inspection access as needed.In the Technical Reference on page 22 under Planning and Implementation, delete the sentence, "While designed primarily with transmission systems in mind, t is also applicable to distribution projects." The Standard should not imply its applicability to distribution systems since it is intended only as a transmission standard.In the Technical Reference, the last sentence on page 26 starting with "Appropriate actions..." should be moved to R5 where it applies. In general, the proposed FAC-003-2 has gone FAR beyond what was contemplated by the Commission in FERC Order 693 and equates to a total re-writing of the Standard for no apparent reason. The Commission's determination dealt with the following areas: (1) applicability; (2) inspection cycles; and (3) minimum clearances on National Forest Service lands. For instance in Paragraph 729, the Commission states, "As proposed in the NOPR, the Commission approves Reliability Standard FAC-003-1 with no proposed modification on the issue of clearances. The Commission reaffirms its interpretation that FAC-003-1 requires sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions...." Rewriting the minimum clearances introduced a new set of confusing definitions, and further burdens the Transmission Owners with new documentation requirements with little if any benefit when compared to the Clearance 2 concept in the existing Standard.A preferred approach would have been to incorporate the following few items into the existing Standard: (1) the RC versus the RRO; (2) the designation of a specific inspection frequency; (3) the Gallet equation; and (4) the applicability to National Forest Service lands.
Ad Hoc Group subteam formed to review draft standard	Yes	The wording in R7 is troublesome. We believe that the process for developing the annual work plan is imbedded in R3. As discussed in question 2, demonstrating capability to actually perform those actions necessary to ensure no vegetation encroachments occur within the MVCD is the primary concern. Deferring such work into the next calendar year appears contrary to this concern and neutralizes the defense-in-depth concept by diminishing the imminent threat requirement of R4 to a primary means of defense. While we don't want to incent vague annual work-plans, we also don't want to remove the imperative that the work must be done.
Nebraska Public Power District	Yes	Under section 4.3.1 add in ice storms as one of the force majeure events. This type of event may impact many TOs and should be included.
Oncor Electric Delivery	Yes	Use of the Gallet equation to determine the minimum gap between vegetation and conductor to prevent sparkover seems to be appropriate. No utility should be managing to this distance but developing a distance beyond this would be arbitrary. This is a reliability standard not a worker safety or vegetation management practices standard. As Federal agencies and other entities are interpreting the Standard to limit normal vegetation management efforts, the FERC should develop and adopt an overarching memo allowing utilities to maintain vegetation under any agency

Organization	Yes or No	Question 13 Comment
		jurisdiction as a utility manages vegetation along the entire right-of-way corridor.
Western Area Power Administration - Upper Great Plains Region	Yes	WAPA - UGPR would like to see "ice storms" specifically mentioned in Section 4.3.1. Having additional clarification as to what is considered a "major storm" would also be helpful.
Bonneville Power Administration	Yes	We believe the minimum vegetation distances are very granular and nearly un-measurable in real life. When a person considers the table to be a list of minimums it seems that the regulated entities, or land owners would want the distances to be as close to the wire as possible. We would not want a non-technical manager to believe that any small distance outside of the noted distances is ok.
Omaha Public Power District	Yes	We have concern over establishing proof an outage is exempt due to fresh gale. A fresh gale, or even a localized thunderstorm, can easily produce wind gusts that exceed the lines rated capacity for blow out. If an outage occurs under these conditions, the standard provides an exemption under Section 4.3.1, but there is often no way to empirically prove conditions exceeded the lines normal operating conditions. How should a utility handle these situations?
Southen Company	Yes	We have concern over establishing proof an outage is exempt due to fresh gale. A fresh gale, or even a localized thunderstorm, can easily produce wind gusts that exceed the lines rated capacity for blow out. If an outage occurs under these conditions, the standard provides an exemption under Section 4.3.1, but there is often no way to empirically prove conditions exceeded the lines normal operating conditions. How should a utility handle these situations? Please note there is a typographical error in the third paragraph on page 15, "...encroachment violation is not be a violation..."We would like to thank the Standard Drafting Team for their hard work. The time and effort they have put into developing this standard is obvious.
Dominion	Yes	While not related solely to this standard, we suggest that no future standard be effective until approval has been granted by the applicable regulatory authority. Having an effective date that differs from the mandatory date is causing confusion/chaos on the part of the applicable registered entity(ies). With the current process, it is possible to have a standard that is mandatory conflict with a superseding newer version (or a new standard that contains requirements meant to supersede those in the mandatory standard). Applicable entity(ies) may not be able to comply with both when this is true, and may not be able to take steps necessary to transition from mandatory requirement to superseding requirement without becoming non-compliant.
Westchester County Board of Legislators		1. Bulk Electricity System NOPR – FERC recently issued a notice of proposed rulemaking to revise the definition of "bulk electric system" (BES) to include all transmission facilities with a rating of 100 kV or above. 130 FERC ¶ 61,204 (Mar. 18, 2010). If approved, such revision might significantly increase the amount of transmission facilities subject to standard FAC-003. In areas with dense residential and commercial development, this revision will exacerbate

Organization	Yes or No	Question 13 Comment
		existing conflicts between homeowners, municipalities, affected transmission owners (TOs), and regulating agencies. As described in comments below, compliance with the existing or perceived requirements in FAC-003 has produced numerous conflict in areas of dense development and narrow rights-of-way between homeowners, TOs, and regulating agencies because of economic, environmental, and aesthetic impacts. If FERC adopts the proposed BES definition, then the FAC-003 standard (current 001 and draft 002) should be extensively reviewed by the drafting team to evaluate the amount of affected facilities and the need for standard revision to avoid as far as possible further conflicts. 2. “Background” Section 5 – The draft adds a new section titled “Background” (Section 5). The existing standard FAC-003-1 does not include a similar section. This narrative section appears to provide interpretation on the rationale for a vegetation management reliability standard and to clarify the standard applicability. This discussion may be more appropriate in the accompanying technical reference, which describes and clarifies standard FAC-003. While identifying overgrown vegetation as cause of major outages and operational problems, this section fails to state that many other causes can lead to Cascading events. Indeed, of the many NERC reliability standards, only one, FAC-003, concerns vegetation management. While the August 2003 blackout was initiated by a tree contact, there were numerous other factors that caused this power outage to spread to over a dozen states. Section 5 should therefore be revised to clarify that FAC-003 is only one of many factors that can lead to a large-scale grid failure. 3. Standard Applicability Across Land Uses – Standard FAC-003-1 and the proposed draft do not vary in applicability, even though the types of land uses within and adjacent to transmission facilities vary widely. Among certain land uses, such as dense residential development, this can lead to substantial conflict between the TO and adjacent landowners, especially concerning environmental, aesthetic, and economic impacts. The Westchester County Board of Legislators identified such problems in its recent resolution, available at http://meetings.westchesterlegislators.com/Citizens/FileOpen.aspx?Type=4&ID=2828&AgencyName=WestchesterCounty . Notwithstanding the reliability imperative expressed by Congress in enacting Section 1211 of the 2005 Energy Policy Act, the implementation of reliability standard FAC-003 has produced significant challenges for all parties in suburban areas. In particular, surburban area homeowners, often on small parcels, that abut or are near to transmission rights-of-way have experienced dramatic impacts upon their properties and property values when TOs exercise their “full extent of legal rights at all times and in all cases”, as stated on page 18 of the draft. Therefore, the development of standard FAC-003 must consider this backdrop and select requirements and accompanying text that provide some balancing of electric reliabilty with environmental and economic impacts. As presently written, the draft does not acknowledge such balance. 4. Varying Conditions – Requirement R1.2.1 of Standard FAC-003-1 identifies numerous local conditions that should be considered in determining appropriate clearance distances. This balanced evaluation of factors should be retained in FAC-003-2. 5. Full Legal Rights – The draft encourages TOs to exercise full legal rights at all times and in all cases. This language

Organization	Yes or No	Question 13 Comment
		is not included in present standard FAC-003-1. As noted above, electric reliabilty and TO compliance with FAC-003 must not preclude other important societal factors. The language encouraging full exercise of legal rights should be removed from the draft.
KCPL	Yes	**<u>Requirement 4:</u>** Recommend the SDT consider modifying R4 to make it clear the requirement applies to that which is within the Right Of Way (ROW) for the transmission facility. Obviously, the Transmission Owner has no authority or control beyond the ROW. This is also an audit concern regarding “triggering” this requirement on a subjective evaluation of “imminent threat”. How does a Registered Entity, Regional Entity or Auditor determine what constitutes an “imminent threat”? This will be a matter of opinion and makes this a difficult requirement regarding compliance when a difference of opinion arises. In addition, as proposed, this requirement does not address the need to take immediate corrective actions to mitigate an imminent threat. The previous FAC-003 Standard included taking action to remove the “imminent threat” which is not included in this proposed version 2. What was the intention of the SDT in this regard? Recommend the SDT consider language to include taking action to remove the imminent threat. **<u>In the “Guideline and Technical Basis” section:</u>** 1. Under R6: believe the word “per” is missing in the first sentence of the third paragraph between “once (per) line”. 2. Under R7: concerned regarding the use of words such as “never”, “at all times”, and “in all cases” in the bulleted items with paragraph 6 in this section as a guiding document. This is the kind of material that is creeping into compliance audits and recommend softening this language. **<u>Violation Severity Levels</u>** 1. Do not agree with the zero tolerance for encroachments that do not result in a service interruption for R1 and R2. 2. Not notifying the Control Center should be a HIGH and not removing the imminent threat should be a SEVERE.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SC approved SAR for initial posting (January 11, 2007).
2. SAR posted for comment (January 15–February 14, 2007).
3. SAR posted for comment (April 10–May 9, 2007).
4. SC authorized moving the SAR forward to standard development (June 27, 2007).

Proposed Action Plan and Description of Current Draft

This is the second posting of the proposed revisions to the standard in accordance with Results-Based Criteria.

Future Development Plan

Anticipated Actions	Anticipated Date
Drafting team considers comments, makes conforming changes, and requests SC approval to proceed to formal comment and ballot.	June –July 2010
Recirculation ballot of standards.	July-August 2010
Receive BOT approval	August 2010

Effective Dates

1. First calendar day of the first calendar quarter one year after applicable regulatory authority approval for all requirements
2. First calendar day of the first calendar quarter one year following Board of Trustees adoption unless governmental authority withholds approval
3. First calendar day of the first calendar quarter that is at least one year following Board of Trustees adoption

Exceptions:

A line operated below 200kV, designated by the Planning Coordinator as an element of an IROL or as a Major WECC transfer path, becomes subject to this standard 12 months after the date the Planning Coordinator or WECC initially designates the lines as being subject to this standard.

An existing transmission line operated at 200kV or higher that is newly acquired by an asset owner and was not previously subject to this standard, becomes subject to this standard 12 months after the acquisition date of the line.

Version History

Version	Date	Action	Change Tracking
1	TBA	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	01/20/06
1	April 4, 2007	Regulatory Approval — Effective Date	New
2			

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary. When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.

Vegetation Inspection
The systematic examination of vegetation conditions on a maintained transmission line Right-of-Way which may be combined with a general line inspection.

The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.

Current definition of Vegetation Inspection: The systematic examination of a transmission corridor to document vegetation conditions.

Introduction

1. **Title:** Transmission Vegetation Management

2. **Number:** FAC-003-2

3. **Objectives:** To improve the reliability of the electric Transmission system by preventing those vegetation related outages that could lead to Cascading.

4. **Applicability**

   4.1. Functional Entities:

   Transmission Owners

   4.2. Facilities: Defined below, including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities:

   4.2.1. Overhead transmission lines operated at 200kV or higher.

   4.2.2. Overhead transmission lines operated below 200kV having been identified as included in the definition of an Interconnection Reliability Operating Limit (IROL) under NERC Standard FAC 014 by the Planning Coordinator.

   4.2.3. Overhead transmission lines operated below 200 kV having been identified as included in the definition of one of the *Major WECC Transfer Paths in the Bulk Electric System*.

   4.2.4. This Standard does not apply to Facilities identified above (4.2.1 through 4.2.3) located in the fenced area of a switchyard, station or substation.

   4.3. Enforcement: *The reliability obligations of the applicable entities and facilities are contained within the technical requirements of this standard. [Straw proposal]*

   4.4. Other:

   This Standard does not apply to any occurrence, non-occurrence, or other set of circumstances that are beyond the control of a Transmission Owner subject to this reliability standard, including acts of God, flood, drought, earthquake, major storms, fire, hurricane, tornado, landslides, ice storms, vehicle contact with tree, human activity involving: removal of, installation of, or digging around vegetation, animals severing trees, lightning, epidemic, strike, war, riot, civil disturbance, sabotage, vandalism, terrorism, wind shear, or fresh gale (or higher wind speed) that restricts or prevents performance to comply with this reliability standard's requirements. Nothing in this

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies"*.

section should be construed to limit the Transmission Owner's right to exercise its full legal rights on the active transmission line ROW[2].

5. Background:

This NERC Vegetation Management Standard ("Standard") uses a defense-in-depth approach to improve the reliability of the electric Transmission System by preventing those vegetation related outages that could lead to Cascading. This Standard is not intended to address non-preventable outages such as those due to vegetation fall-ins or blow-ins from outside the Active Transmission Line Right-of-Way, vandalism, human activities and acts of nature. Operating experience indicates that trees that have grown out of specification have contributed to Cascading, especially under heavy electrical loading conditions.

With a defense-in-depth strategy, this Standard utilizes three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

a) Performance-based — defines a particular reliability objective or outcome to be achieved.

b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels.

c) Competency-based — defines a minimum capability an entity needs to have to demonstrate it is able to perform its designated reliability functions.

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard. For this Standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

Thus the various requirements associated with a successful vegetation program could be viewed as using R1, R2 and R3 as first levels of defense; while R4 could be a subsequent or final level of defense. R6 depending on the particular vegetation approach may be either an initial defense barrier or a final defense barrier.

[2] A strip or corridor of land that is occupied by active transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities. However, it is not to be less than the width of the easement itself unless the easement exceeds distances as shown in Table 3 for various voltage classes.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the Standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the Standard the term "public lands" includes municipal lands, village lands, city lands, and a host of other governmental entities.

This Standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This Standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this Standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of multiple line failures and Cascading. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are statistically intermittent. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this Standard's emphasis is on vegetation grow-ins.

Requirements and Measures

Rationale
The MVCD is a calculated minimum distance stated in feet (meters) to prevent spark-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method.

R1. Each Transmission Owner shall manage vegetation to prevent encroachment that could result in a Sustained Outage of any line identified as an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions). Types of encroachment include:

1. An encroachment into the Minimum Vegetation Clearance Distance (MVCD) as shown in Table 2, observed in real time, absent a Sustained Outage,
2. An encroachment due to a fall-in from inside the active transmission line ROW that caused a vegetation-related Sustained Outage,
3. An encroachment due to blowing together of applicable lines and vegetation located inside the active transmission line ROW that caused a vegetation-related Sustained Outage,
4. An encroachment due to a grow-in that caused a vegetation-related Sustained Outage.

[VRF – High] [Time Horizon – Real-time]

M1. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-Time observations of any MVCD encroachments.

Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. If an investigation of a Fault by a qualified person confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered a Real-time observation.

R2. Each Transmission Owner shall manage vegetation to prevent encroachment that could result in a Sustained Outage of applicable lines that are not elements of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions). Types of encroachment include:

1. An encroachment into the Minimum Vegetation Clearance Distance (MVCD) as shown in Table 2, observed in real time, absent a Sustained Outage,
2. An encroachment due to a fall-in from inside the active transmission line ROW that caused a vegetation-related Sustained Outage,
3. An encroachment due to blowing together of applicable lines and vegetation located inside the active transmission line ROW that caused a vegetation-related Sustained Outage,
4. An encroachment due to a grow-in that caused a vegetation-related Sustained Outage.

[VRF – Medium] [Time Horizon – Real-time]

Rationale

The MVCD is a calculated minimum distance stated in feet (meters) to prevent spark-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method.

M2. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-Time observations of any MVCD encroachments.

Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. If an investigation of a Fault by a qualified person confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered a Real-time observation.

R3. Each Transmission Owner shall document the procedures, processes, or specifications it uses to prevent the encroachment of vegetation into the MVCD. Such documentation will incorporate the dynamics of a transmission line conductor’s movement throughout its Rating and Rated Electrical Operating Conditions and the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the Transmission Owner’s applicable lines.

> **Rationale**
> Provide a basis for evaluation on the intent and competency of the Transmission Owner in maintaining vegetation. There may be many acceptable approaches to maintain clearances. However, the Transmission Owner should be able to state what its approach is and how it conducts work to maintain clearances. See Figure 1 for an illustration of possible conductor locations.

[VRF – Lower] [Time Horizon – Long Term Planning]

M3. The procedures, processes, or specifications provided demonstrate that the Transmission Owner can prevent encroachment into the MVCD considering the factors identified in the requirement.

R4. Each Transmission Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated transmission line when qualified personnel confirm the existence of a vegetation condition that is likely to cause a Fault at any moment.

> **Rationale**
> To ensure expeditious communication between qualified field personnel and proper operating personnel when a critical situation is confirmed. Qualified field personnel may include lineworkers and utility arborists.

[VRF – Medium] [Time Horizon – Real-time]

M4. Each Transmission Owner that has a vegetation condition likely to cause a Fault at any moment, as confirmed by qualified personnel, will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders.

R5. Each Transmission Owner shall take corrective action when it is constrained from performing planned vegetation work, where a transmission line is put at potential risk due to the constraint.

[VRF – Medium] [Time Horizon – Operations Planning]

M5. Each Transmission Owner has evidence of the corrective action taken for each constraint where a transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, and evidence that a line was de-energized.

Rationale

Legal actions and other events may occur which result in constraints that prevent the Transmission Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the Transmission Owner to put interim measures in place, rather than do nothing.

For example, in the 2003 NE blackout a Transmission Owner was prevented by a court order from performing planned work. However, when the court order expired, the TO failed to take action to maintain the vegetation resulting in a sustained outage that contributed to the cascade.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

R6. Each Transmission Owner shall perform a Vegetation Inspection of all applicable transmission lines at least once per calendar year.

[VRF – Medium] [Time Horizon – Operations Planning]

M6. Each Transmission Owner has evidence that it conducted Vegetation Inspections at least once per calendar year for all applicable transmission lines. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records.

Rationale

Inspections are used by Transmission Owners to assess the condition of the ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

R7. Each Transmission Owner shall complete the work in an annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk of a vegetation encroachment. Examples of reasons for modification to annual plan may include:

- Change in expected growth rate/ environmental factors
- Major storms
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Funding adjustments (increase or decrease)
- Emerging technologies

Rationale

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. An annual vegetation work plan allows for work to be modified for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that the changes do not violate the encroachment within the MVCD.

[VRF – Medium] [Time Horizon – Operations Planning]

M7. Each Transmission Owner has evidence that it completed its annual vegetation work plan. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (including modifications if any), dated work orders, dated invoices, or dated inspection records.

Compliance

Compliance Enforcement Authority

- Regional Entity

Compliance Monitoring and Enforcement Processes:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

Evidence Retention

The Transmission Owner retains data or evidence of Requirements R1 through R7, Measures M1 through M7 for three calendar years to show compliance unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant, or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

Additional Compliance Information

Periodic Data Submittal: The Transmission Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of transmission lines determined by the Transmission Owner to have been caused by vegetation that includes, as a minimum, the following:

- o The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.

A Sustained Outage is to be categorized as one of the following:

- o Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable transmission lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the active transmission line ROW;

- o Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable transmission lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the active transmission line ROW;

- Category 2 — Fall-ins: Sustained Outages caused by vegetation falling into applicable transmission lines from within the active transmission line ROW;
- Category[3] 4 — Blowing together: Sustained Outages caused by vegetation and applicable transmission lines blowing together from within the active transmission line ROW.

The Regional Entity will report the outage information provided by Transmission Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

[3] Category 3 reporting is eliminated.

At the request of the Standards Committee, stakeholders are asked to review and comment on the proposed VSLs for R1 and R2. Following the comment period and nonbinding poll, only one set of VSLs will move forward for R1 and R2.

Time Horizons, Violation Risk Factors, and Violation Severity Levels

Table 1

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1-SDT Version	Real-time	High	The Transmission Owner had an encroachment into the MVCD observed in real time, absent a Sustained Outage.	The Transmission Owner had an encroachment due to a fall-in from inside the active transmission line ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner had an encroachment due to blowing together of applicable lines and vegetation located inside the active transmission line ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner had an encroachment due to a grow-in that caused a vegetation-related Sustained Outage.
R1 Staff Version	Real-time	High			The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.	The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: • A fall-in from inside the active transmission line ROW • Blowing together of applicable lines and vegetation located inside the active transmission line ROW • A grow-in
R2-SDT Version	Real-time	Medium	The Transmission Owner had an encroachment into the MVCD observed in real time, absent a	The Transmission Owner had an encroachment due to a fall-in from inside the active transmission line	The Transmission Owner had an encroachment due to blowing together of applicable lines and vegetation located inside the	The Transmission Owner had an encroachment due to a grow-in that caused a vegetation-related Sustained Outage.

Table 1						
R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
			Sustained Outage.	ROW that caused a vegetation-related Sustained Outage.	active transmission line ROW that caused a vegetation-related Sustained Outage.	
R2 Staff Version	Real-time	Medium			The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.	The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: • A fall-in from inside the active transmission line ROW • Blowing together of applicable lines and vegetation located inside the active transmission line ROW • A grow-in
R3	Long-Term Planning	Lower		The Transmission Owner has documented the procedures, processes, or specifications but does not incorporate the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency,	The Transmission Owner has documented the procedures, processes, or specifications but does not incorporate the dynamics of a transmission line conductor’s movement throughout its Rating and Rated Electrical Operating Conditions, for the Transmission Owner’s	The Transmission Owner does not have any documented procedures, processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the Transmission Owner’s applicable lines.

Table 1						
R#	**Time Horizon**	**VRF**	**Violation Severity Level**			
			Lower	**Moderate**	**High**	**Severe**
				for the Transmission Owner's applicable lines.	applicable lines.	
R4	Real-time	Medium			The Transmission Owner experienced a vegetation threat confirmed by qualified personnel and notified the control center holding switching authority for that transmission line, but there was intentional delay in that notification.	The Transmission Owner experienced a vegetation threat confirmed by qualified personnel and did not notify the control center holding switching authority for that transmission line.
R5	Operations Planning	Medium				The Transmission Owner did not take corrective action when it was constrained from performing planned vegetation work where a transmission line was put at potential risk.
R6	Operations Planning	Medium	The Transmission Owner failed to inspect 5% or less of the ROW as measured by applicable-line miles (kilometers) (based on units of choice: circuit, pole line, ROW, etc.).	The Transmission Owner failed to inspect more than 5% up to and including 10% of the ROW as measured by applicable-line miles (kilometers) (based on units of choice: circuit, pole line, ROW, etc.).	The Transmission Owner failed to inspect more than 10% up to and including 15% of the ROW as measured by applicable-line miles (kilometers) (based on units of choice: circuit, pole line, ROW, etc.).	The Transmission Owner failed to inspect more than 15% of the ROW as measured by applicable-line miles (kilometers) (based on units of choice: circuit, pole line, ROW, etc.).
R7	Operations Planning	Medium	The Transmission Owner failed to complete up to 5% of its annual work plan (including modifications if any).	The Transmission Owner failed to complete more than 5% and up to 10% of its annual work plan (including modifications if	The Transmission Owner failed to complete more than 10% and up to 15% of its annual work plan (including modifications if any).	The Transmission Owner failed to complete more than 15% of its annual work plan (including modifications if any).

Table 1							
R#	Time Horizon	VRF	Violation Severity Level				
			Lower	Moderate	High	Severe	
				any).			

Variances

None.

Interpretations

None.

Guidelines and Technical Basis

Requirements R1 and R2:
R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the prevention of vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each Transmission Owner to prevent vegetation from encroaching within the Minimum Vegetation Clearance Distance of transmission lines. R1 is applicable to lines “identified as an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions) to avoid a Sustained Outage”. R2 applies to all other applicable lines that are not an element of an IROL or Major WECC Transfer Path.

The separation of applicability (between R1 and R2) recognizes that an encroachment into the MVCD of an IROL or Major WECC Transfer Path transmission line is a greater risk to the electric transmission system. Applicable lines that are not an element of an IROL or Major WECC Transfer Path are required to be clear of vegetation but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

These requirements (R1 and R2) state that if vegetation encroaches within the distances prescribed in Table 2, it is in violation of the standard. Table 2 delineates the distances necessary to prevent spark-over based on the Gallet equations as described more fully in a supplemental *Transmission Vegetation Management Standard FAC-003-2 Technical Reference*.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating (potentially in violation of other standards), the occurrence of a clearance encroachment may occur. For example, emergency actions taken by a Transmission Operator or Reliability Coordinator to protect an Interconnection may cause the transmission line to sag more and come closer to vegetation, potentially causing an outage. Such vegetation-related outages are not a violation of these requirements.

Evidence of violation of Requirement R1 and R2 include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the active transmission line ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to blowing together of applicable lines and vegetation located inside the active transmission line ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. If an investigation of a Fault by a qualified person confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered a Real-time observation.

With this approach, the VSLs were defined such that they directly correlate to the severity of a failure to keep vegetation away from conductors and to the corresponding performance level of the Transmission Owner’s vegetation program’s ability to meet the goal of “preventing a Sustained Outage that could lead to Cascading.” Thus violation severity increases with a Transmission Owner’s inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation, for example a limb that only partially breaks and intermittently contacts a conductor. Such events are considered to be a single vegetation-related Sustained Outage under the Standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will help prevent transmission outages.

Requirement R3:

Requirement R3 is a competency based requirement concerned with the procedures, processes, or specifications, a Transmission Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the Transmission Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the Transmission System. The approach provides the basis for evaluating the intent, allocation of appropriate resources and the competency of the Transmission Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the Transmission Owner must be able to state what its approach is and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach a Transmission Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the Transmission Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing as a reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below.

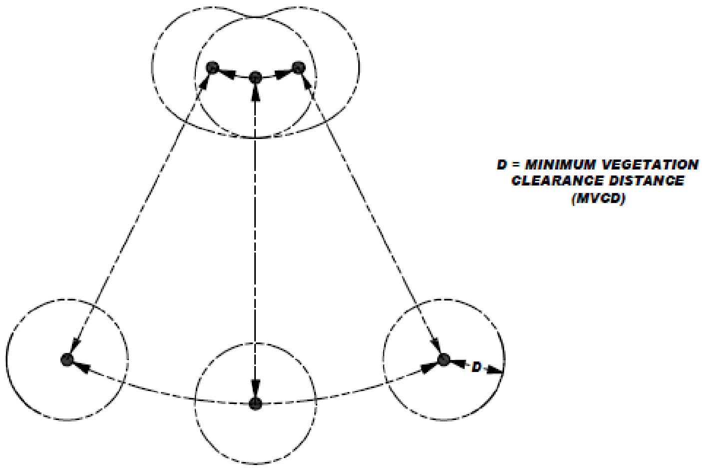


Figure 1

Cross-section view of a single conductor at a given point along the span showing six possible conductor positions due to movement resulting from thermal and mechanical loading.

Requirement R4:

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the Transmission Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of a qualified employee who personally identifies such a threat in the field. Confirmation could also be made by sending out a qualified person to evaluate a situation reported by a landowner or an unqualified employee.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The Transmission Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or positioning the system in recognition of the increasing risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some Transmission Owners may have a danger tree identification

program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5:
R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the Transmission Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the Transmission Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the Transmission Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the Transmission Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the Transmission Owner is required to take corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the Transmission Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for each location.
- In developing the specific action to mitigate the potential risk to the transmission line the Transmission Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The Transmission Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:
R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections that fits general industry practice. In addition, the fact that Vegetation Inspections can be performed in conjunction with general line inspections further facilitates a

Transmission Owner's ability to meet this requirement. However, the Transmission Owner may determine that more frequent inspections are needed to maintain reliability levels, dependent upon such factors as anticipated growth rates of the local vegetation, length of the growing season for the geographical area, limited Active Transmission ROW width, and rainfall amounts. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSL for Requirement R6 has VSL categories ranked by the percentage of the required ROW inspections completed. To calculate the percentage of inspection completion, the Transmission Owner may choose units such as: line miles or kilometers, circuit miles or kilometers, pole line miles, ROW miles, etc.

For example, when a Transmission Owner operates 2,000 miles of 230 kV transmission lines this Transmission Owner will be responsible for inspecting all 2,000 miles of 230 kV transmission lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

Requirement R7:
R7 is a risk-based requirement. The Transmission Owner is required to implement an annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a "span-by-span", or even a "line-by-line" detailed description of all work to be performed. It is only intended to require that the Transmission Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

The ability to modify the work plan allows the Transmission Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the Transmission Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan. Modifications to the annual work plan must always ensure the reliability of the electric Transmission system.

In general, the vegetation management maintenance approach should use the full extent of the Transmission Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the active transmission line ROW is superior to incremental management in the long term because it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the Transmission Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Transmission Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the Transmission Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[4]

For **Alternating Current** Voltages

(AC) Nominal System Voltage (kV)	(AC) Maximum System Voltage (kV)	MVCD feet (meters) sea level	MVCD feet (meters) 3,000ft (914.4m)	MVCD feet (meters) 4,000ft (1219.2m)	MVCD feet (meters) 5,000ft (1524m)	MVCD feet (meters) 6,000ft (1828.8m)	MVCD feet (meters) 7,000ft (2133.6m)	MVCD feet (meters) 8,000ft (2438.4m)	MVCD feet (meters) 9,000ft (2743.2m)	MVCD feet (meters) 10,000ft (3048m)	MVCD feet (meters) 11,000ft (3352.8m)
765	800	8.06ft (2.46m)	8.89ft (2.71m)	9.17ft (2.80m)	9.45ft (2.88m)	9.73ft (2.97m)	10.01ft (3.05m)	10.29ft (3.14m)	10.57ft (3.22m)	10.85ft (3.31m)	11.13ft (3.39m)
500	550	5.06ft (1.54m)	5.66ft (1.73m)	5.86ft (1.79m)	6.07ft (1.85m)	6.28ft (1.91m)	6.49ft (1.98m)	6.7ft (2.04m)	6.92ft (2.11m)	7.13ft (2.17m)	7.35ft (2.24m)
345	362	3.12ft (0.95m)	3.53ft (1.08m)	3.67ft (1.12m)	3.82ft (1.16m)	3.97ft (1.21m)	4.12ft (1.26m)	4.27ft (1.30m)	4.43ft (1.35m)	4.58ft (1.40m)	4.74ft (1.44m)
230	242	2.97ft (0.91m)	3.36ft (1.02m)	3.49ft (1.06m)	3.63ft (1.11m)	3.78ft (1.15m)	3.92ft (1.19m)	4.07ft (1.24m)	4.22ft (1.29m)	4.37ft (1.33m)	4.53ft (1.38m)
161*	169	2ft (0.61m)	2.28ft (0.69m)	2.38ft (0.73m)	2.48ft (0.76m)	2.58ft (0.79m)	2.69ft (0.82m)	2.8ft (0.85m)	2.91ft (0.89m)	3.03ft (0.92m)	3.14ft (0.96m)
138*	145	1.7ft (0.52m)	1.94ft (0.59m)	2.03ft (0.62m)	2.12ft (0.65m)	2.21ft (0.67m)	2.3ft (0.70m)	2.4ft (0.73m)	2.49ft (0.76m)	2.59ft (0.79m)	2.7ft (0.82m)
115*	121	1.41ft (0.43m)	1.61ft (0.49m)	1.68ft (0.51m)	1.75ft (0.53m)	1.83ft (0.56m)	1.91ft (0.58m)	1.99ft (0.61m)	2.07ft (0.63m)	2.16ft (0.66m)	2.25ft (0.69m)
88*	100	1.15ft (0.35m)	1.32ft (0.40m)	1.38ft (0.42m)	1.44ft (0.44m)	1.5ft (0.46m)	1.57ft (0.48m)	1.64ft (0.50m)	1.71ft (0.52m)	1.78ft (0.54m)	1.86ft (0.57m)
69*	72	0.82ft (0.25m)	0.94ft (0.29m)	0.99ft (0.30m)	1.03ft (0.31m)	1.08ft (0.33m)	1.13ft (0.34m)	1.18ft (0.36m)	1.23ft (0.37m)	1.28ft (0.39m)	1.34ft (0.41m)

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above).

[4] The distances in this Table are the minimums required to prevent Flashover; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

Table 2 (cont.) — Minimum Vegetation Clearance Distances (MVCD)
For **Direct Current** Voltages

(DC) Nominal Pole to Ground Voltage (kV)	MVCD feet (meters) sea level	MVCD feet (meters) 3,000ft (914.4m) Alt.	MVCD feet (meters) 4,000ft (1219.2m) Alt.	MVCD feet (meters) 5,000ft (1524m) Alt.	MVCD feet (meters) 6,000ft (1828.8m) Alt.	MVCD feet (meters) 7,000ft (2133.6m) Alt.	MVCD feet (meters) (8,000ft (2438.4m) Alt.	MVCD feet (meters) 9,000ft (2743.2m) Alt.	MVCD feet (meters) 10,000ft (3048m) Alt.	MVCD feet (meters) 11,000ft (3352.8m) Alt.
±750	13.92ft (4.24m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.9ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.07ft (3.07m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	(13.54ft 4.13m)
±500	7.89ft (2.40m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	4.78ft (1.46m)	5.35ft (1.63m)	5.55ft (1.69m)	5.75ft (1.75m)	5.95ft (1.81m)	6.15ft (1.87m)	6.36ft (1.94m)	6.57ft (2.00m)	6.77ft (2.06m)	6.98ft (2.13m)
±250	3.43ft (1.05m)	4.02ft (1.23m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5ft (1.52m)	5.17ft (1.58m)

Table 3 – Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW

69 - 138 kV	37.5 ft.
139 - 230 kV	50 ft.
231 - 345 kV	75 ft.
346 - 500 kV	87.5 ft.
501 - 765 kV	100 ft.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SC approved SAR for initial posting (January 11, 2007).
2. SAR posted for comment (January 15–February 14, 2007).
3. SAR posted for comment (April 10–May 9, 2007).
4. SC authorized moving the SAR forward to standard development (June 27, 2007).

Proposed Action Plan and Description of Current Draft

This is the second~~first~~ posting of the proposed revisions to the standard in accordance with Results-Based Criteria. ~~The drafting team requests posting for a 30-day informal comment period.~~

Future Development Plan

Anticipated Actions	Anticipated Date
~~Drafting team considers comments, makes conforming changes, posts for 30-day informal comment period.~~	~~April 2010~~
Drafting team considers comments, makes conforming changes, and requests SC approval to proceed to formal comment and ballot.	June –July 2010
Recirculation ballot of standards.	July-August 2010
Receive BOT approval	August~~September~~ 2010

~~Definitions of Terms Used in Standard~~

~~This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.~~

~~Active Transmission Line Right-of-Way~~
~~A strip or corridor of land that is occupied by active transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities.~~

~~Examples of active portions of corridors include:~~
~~The width of any Active Transmission Line Right-of-Way (ROW) is the portion of the ROW that has been cleared of vegetation to meet design clearance requirements such as National Electrical Safety Code or other design criteria, for the reliable operation of active facilities.~~

~~Examples of inactive portions of corridors include:~~

1) ~~The portions of the ROW acquired to accommodate future Facilities. Power plant exits are examples where large ROWs are obtained for maximum corridor utilization and may currently have fewer circuits constructed.~~
2) ~~The portion of the ROW where corridor edge zones are designated by regulatory bodies for vegetation to exist.~~
3) ~~The portions of the ROW where double-circuit structures are installed but only one circuit is currently strung with conductors.~~

~~Vegetation Inspection~~
~~The systematic examination of vegetation conditions on an Active Transmission Line Right-of-Way which may be combined with a general line inspection.~~

~~The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.~~

~~Current definition of Vegetation Inspection: The systematic examination of a transmission corridor to document vegetation conditions.~~

Effective Dates

~~Requirement~~	~~Jurisdiction~~							
	~~Alberta~~	~~British Columbia~~	~~Manitoba~~	~~New Brunswick~~	~~Newfound-land~~	~~Nova Scotia~~	~~Ontario~~	~~Quebec~~
~~R1~~	~~1~~	~~1~~	~~1~~	~~3~~	~~TBD~~	~~TBD~~	~~2~~	~~TBD~~
~~R2~~	~~1~~	~~1~~	~~1~~	~~3~~	~~TBD~~	~~TBD~~	~~2~~	~~TBD~~
~~R3~~	~~1~~	~~1~~	~~1~~	~~3~~	~~TBD~~	~~TBD~~	~~2~~	~~TBD~~
~~R4~~	~~1~~	~~1~~	~~1~~	~~3~~	~~TBD~~	~~TBD~~	~~2~~	~~TBD~~
~~R5~~	~~1~~	~~1~~	~~1~~	~~3~~	~~TBD~~	~~TBD~~	~~2~~	~~TBD~~
~~R6~~	~~1~~	~~1~~	~~1~~	~~3~~	~~TBD~~	~~TBD~~	~~2~~	~~TBD~~
~~R7~~	~~1~~	~~1~~	~~1~~	~~3~~	~~TBD~~	~~TBD~~	~~2~~	~~TBD~~

1. First calendar day of the first calendar quarter one year after applicable regulatory authority approval for all requirements
2. First calendar day of the first calendar quarter one year following Board of Trustees adoption unless governmental authority withholds approval
3. First calendar day of the first calendar quarter that is at least one year following Board of Trustees adoption

Exceptions:

A line~~**Lines**~~ **operated below 200kV, designated by the Planning Coordinator as** an element of an IROL **or as** a Major WECC transfer p**ath,** becomes~~**become**~~ **subject to this standard 12 months after the date the Planning Coordinator or WECC initially designates the lines as being subject to this standard.**

An e**xisting** t**ransmission** l**ine operated at 200kV or higher that is newly acquired by an** asset o**wner and was not previously subject to this standard, become**s **subject to this standard 12 months after the acquisition date of the line**.~~**(s).**~~

Version History

Version	Date	Action	Change Tracking
1	TBA	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	01/20/06
1	April 4, 2007	Regulatory Approval — Effective Date	New
2			

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary. When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.

Vegetation Inspection
The systematic examination of vegetation conditions on a maintained transmission line Right-of-Way which may be combined with a general line inspection.

The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.

Current definition of Vegetation Inspection: The systematic examination of a transmission corridor to document vegetation conditions.

Introduction

1. **Title:** Transmission Vegetation Management

2. **Number:** FAC-003-2

3. **Objectives:** To improve the reliability of the electric Transmission system by preventing those vegetation related outages that could lead to Cascading.

4. **Applicability**

4.1. Functional Entities:

~~**4.1.1**~~ Transmission Owners

4.2. Facilities: Defined below, including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities:

~~**4.2.1.**~~ **4.2.1.** Overhead transmission lines operated at 200kV or higher.

~~**4.2.2.**~~ **4.2.2.** Overhead transmission lines operated below 200kV having been identified as included in the definition~~**elements**~~ of an Interconnection Reliability Operating Limit (IROL) under NERC Standard FAC 014 by the Planning Coordinator.~~).~~

~~**4.2.3.**~~ **4.2.3.** Overhead transmission lines operated below 200 kV having been identified as included in the definition of one of the *Major WECC Transfer Paths in the Bulk Electric System*.

~~**4.2.4.**~~ **4.2.4.** This Standard does not apply to Facilities identified above (4.2.1 through 4.2.3) located in the fenced area of a switchyard, station or substation.

4.3. Enforcement: *The reliability obligations of the applicable entities and facilities are contained within the technical requirements of this standard. [Straw proposal]*

~~**4.3.**~~4.4. **Other:**

~~**4.3.1.**~~ This Standard does not apply to any occurrence, non-occurrence, or other set of circumstances that are beyond the ~~reasonable~~ control of a Transmission Owner subject to this reliability standard~~Reliability Standard, and are not caused by the fault or negligence of the Transmission Owner~~, including acts of God, flood, drought, earthquake, major storms, fire, hurricane, tornado, landslides, ice storms, vehicle contact with tree, human activity involving: removal of, installation of, or digging around vegetation~~logging activities~~, animals severing trees, lightning, epidemic, strike, war, riot, civil disturbance, sabotage, vandalism, terrorism, wind shear, or fresh gale (or higher wind speed)~~gales~~ that restricts or prevents performance to comply with this reliability standard's requirements. Nothing in this section should be construed to limit

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies"*.

the Transmission Owner's right to exercise its full legal rights on the active transmission line ROW[2].

5. Background:

This NERC Vegetation Management Standard ("Standard") uses a defense-in-depth approach to improve the reliability of the electric Transmission System by preventing those vegetation related outages that could lead to Cascading. This Standard is not intended to address non-preventable outages such as those due to vegetation fall-ins or blow-ins from outside the Active Transmission Line Right-of-Way, vandalism, human activities~~errors~~ and acts of nature. Operating experience indicates that trees that have grown out of specification have contributed to Cascading, especially under heavy electrical loading conditions.

With a defense-in-depth strategy, this Standard utilizes three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

a) Performance-based — defines a particular reliability objective or outcome to be achieved.

b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels.

c) Competency-based — defines a minimum capability an entity needs to have to demonstrate it is able to perform its designated reliability functions.

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard. For this Standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

Thus the various requirements associated with a successful vegetation program could be viewed as using R1, R2 and R3 as first levels of defense; while R4 could be a subsequent or final level of defense. R6 depending on the particular vegetation approach may be either an initial defense barrier or a final defense barrier.

[2] A strip or corridor of land that is occupied by active transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities. However, it is not to be less than the width of the easement itself unless the easement exceeds distances as shown in Table 3 for various voltage classes.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the Standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the Standard the term "public lands" includes municipal lands, village lands, city lands, and a host of other governmental entities.

This Standard addresses vegetation management along applicable overhead lines and~~that serve to connect one electric station to another. However, this Standard~~ does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This Standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this Standard is not written to address such isolated situations which have little impact on the overall electric transmission system~~Bulk Electric System~~.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of multiple line failures and Cascading. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are statistically intermittent. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this Standard's emphasis is on vegetation grow-ins.

Requirements and Measures

> **Rationale**
> The MVCD is a calculated minimum distance stated in feet (meters) to prevent spark-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method.

R1. Each Transmission Owner shall manage ~~prevent~~ vegetation to prevent encroachment that could result in a Sustained Outage~~from encroaching within the Minimum Vegetation Clearance Distance (MVCD)~~ of any~~each~~ line ~~conductor that is~~ identified as an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions). Types of encroachment include:~~) to avoid a Sustained Outage.~~

An

~~**M1.** Evidence of violation of Requirement R1 is limited to:~~

1. ~~**Real-time observation of**~~ encroachment into the Minimum Vegetation Clearance Distance (MVCD) as shown in Table 2, observed in real time, absent a Sustained Outage,~~, **or**~~
    - **An encroachment**~~A vegetation-related Sustained Outage~~ due to a fall-in from inside the **active transmission line**~~Active Transmission Line~~ ROW **that caused a**~~, or~~
2. ~~**A**~~ vegetation-related Sustained Outage,
    - **An encroachment** due to blowing together of applicable lines and vegetation located inside the **active transmission line**~~Active Transmission Line~~ ROW **that caused a**~~, or~~
3. ~~**A**~~ vegetation-related Sustained Outage,
4. An encroachment due to a grow-in that caused a vegetation-related Sustained Outage.

[VRF – High] [Time Horizon – Real-time]

M1. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-Time observations of any MVCD encroachments.

Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. If an investigation of a Fault by a qualified person confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered a Real-time observation.

R2. Each Transmission Owner shall manage vegetation to prevent encroachment that could result in a Sustained Outage of applicable lines that are not elements of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions). Types of encroachment include:

1. An encroachment into the Minimum Vegetation Clearance Distance (MVCD) as shown in Table 2, observed in real time, absent a Sustained Outage,
2. An encroachment due to a fall-in from inside the active transmission line ROW that caused a vegetation-related Sustained Outage,
3. An encroachment due to blowing together of applicable lines and vegetation located inside the active transmission line ROW that caused a vegetation-related Sustained Outage,
4. An encroachment due to a grow-in that caused a vegetation-related Sustained Outage.

Rationale

The MVCD is a calculated minimum distance stated in feet (meters) to prevent spark-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method.

[VRF – Medium] [Time Horizon – Real-time]

- **M2.** Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-Time observations of any MVCD encroachments.

  Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. If an investigation of a Fault by a qualified person confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered a Real-time observation.

R3~~R2~~. Each Transmission Owner shall document the procedures, processes, or specifications it uses to prevent the encroachment of vegetation into~~from encroaching within~~ the MVCD. Such documentation will incorporate the dynamics of a transmission ~~of each applicable~~ line conductor's movement throughout its ~~conductor, which are not elements of an IROL and are not a Major WECC transfer path, (operating within~~ Rating and Rated Electrical Operating Conditions and the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the Transmission Owner's applicable lines) ~~to avoid a Sustained Outage~~.

~~**Rationale**~~

~~The MVCD is a calculated minimum distance stated in feet (meters) to prevent spark-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven~~

Rationale

Provide a basis for evaluation on the intent and competency of the Transmission Owner in maintaining vegetation. There may be many acceptable approaches to maintain clearances. However, the Transmission Owner should be able to state what its approach is and how it conducts work to maintain clearances. See Figure 1 for an illustration of possible conductor locations.

[VRF – Lower] [Time Horizon – Long Term Planning]

M3. The procedures, processes, or specifications provided demonstrate that the Transmission Owner can prevent

~~**M2.** Evidence of violation of Requirement R2 is limited to:~~

- ~~Real-time observation of~~ encroachment into the MVCD~~, or~~
- ~~A vegetation-related Sustained Outage due to a fall-in from inside the Active Transmission Line ROW, or~~
- ~~A vegetation-related Sustained Outage due to blowing together of applicable lines and vegetation located inside the Active Transmission Line ROW, or~~
- ~~A vegetation-related Sustained Outage due to a grow-in.~~

~~Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.~~

~~**R3.** Each Transmission Owner shall have a documented transmission vegetation management program that describes how it conducts work on its Active Transmission Line ROWs to avoid Sustained Outages due to vegetation,~~ considering the factors identified in the requirement~~all possible locations the conductor may occupy assuming operation within Rating and Rated Electrical Operating Conditions~~.

Rationale

To ensure expeditious communication between qualified field personnel and proper operating personnel when a critical situation is confirmed. Qualified field personnel may include lineworkers and utility arborists.

~~Rationale~~

~~Provide a basis for evaluation on the intent and competency of the Transmission Owner in maintaining vegetation. There may be many acceptable approaches to maintain clearances. However, the Transmission Owner should be able to state what its approach is and how it conducts work to maintain clearances. See Figure 1 for an illustration of possible conductor locations.~~

~~**M3.** Each Transmission Owner has a documented transmission vegetation management program that describes how it conducts work on its Active Transmission Line ROW to avoid Sustained Outages due to vegetation, considering all possible locations the conductor may occupy assuming operation within Rating and Rated Electrical Operating Conditions.~~

R4. Each Transmission Owner, without any intentional time delay, shall notify the ~~responsible~~ control center holding switching authority for the associated transmission line when qualified personnel confirm the existence~~it has verified knowledge~~ of a vegetation ~~imminent threat~~ condition that ~~. A vegetation imminent threat condition is one which~~ is likely to cause a Fault~~Sustained Outage~~ at any moment.

[VRF – Medium] [Time Horizon – Real-time]

~~Rationale~~

~~To ensure rapid notification of the correct personnel when an occurrence of a critical situation is observed. Verified knowledge includes observations by journeyman lineman, utility arborist, or other qualified personnel, or a report verified by these personnel.~~

M4. Each Transmission Owner that has a vegetation condition likely to cause a Fault at any moment, as confirmed by qualified personnel,~~experienced a verified vegetation imminent threat~~ will have evidence that it notified the ~~responsible~~ control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders.

R5. Each Transmission Owner shall take ~~interim~~ corrective action when it is ~~temporarily~~ constrained from performing planned vegetation work, where a transmission line is put at potential risk due to the constraint.

[VRF – Medium] [Time Horizon – Operations Planning]

M5. Each Transmission Owner has evidence of the ~~interim~~ corrective action taken for each ~~temporary~~ constraint where a transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, and evidence that a line was de-energized~~or inspection records~~.

Rationale

Legal actions and other events may occur which result in constraints that prevent the Transmission Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the Transmission Owner to put interim measures in place, rather than do nothing.

For example, in the 2003 NE blackout a Transmission Owner was prevented by a court order from performing planned work. However, when the court order expired, the TO failed to take action to maintain the vegetation resulting in a sustained outage that contributed to the cascade.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

R6. Each Transmission Owner shall perform a Vegetation Inspection of all applicable transmission lines at least once per calendar year.

[VRF – Medium] [Time Horizon – Operations Planning]

M6. Each Transmission Owner has evidence that it conducted Vegetation Inspections at least once per calendar year for all applicable transmission lines. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records.

Rationale

Inspections are used by Transmission Owners to assess the condition of the ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar

R7. Each Transmission Owner shall complete the work in an~~execute a flexible~~ annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk of a vegetation encroachment. Examples of reasons for modification to annual plan may include:

Rationale

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. An annual vegetation work plan allows for work to be modified for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that the changes do not violate the encroachment within the MVCD.

- Change in expected growth rate/ environmental factors
- Major storms
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Funding adjustments (increase or decrease)
- Emerging technologies

[VRF – Medium] [Time Horizon – Operations Planning]

M7. Each Transmission Owner has evidence that it completed its~~executed a flexible~~ annual vegetation work plan. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (including modifications if any), dated work orders, dated invoices, or dated inspection records.

Compliance

Compliance Enforcement Authority

- Regional Entity

Compliance Monitoring and Enforcement Processes:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

Evidence Retention

The Transmission Owner retains data or evidence of Requirements R1 through R7, Measures M1 through M7 for three calendar years to show compliance unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant, or for the duration specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

Additional Compliance Information

Periodic Data Submittal: ~~(See Administrative Procedure)~~

~~Time Horizons, Violation Risk Factors, and Violation Severity Levels~~

~~Table 1~~							
~~R#~~		~~Time Horizon~~	~~VRF~~	~~Violation Severity Level~~			
				~~Lower~~	~~Moderate~~	~~High~~	~~Severe~~
~~R1~~		~~Real-time~~	~~High~~	~~The Transmission Owner failed to prevent vegetation from encroaching within the MVCD of a transmission line as described in R1.~~	~~The Transmission Owner incurred a Sustained Outage due to vegetation falling into a transmission line as described in R1 from within the Active Transmission Line ROW.~~	~~The Transmission Owner incurred a Sustained Outage due to the blowing together of vegetation and a transmission line as described in R1 from within the Active Transmission Line ROW.~~	~~The Transmission Owner incurred a Sustained Outage due to vegetation growing into a transmission line as described in R1.~~
~~R2~~		~~Real-time~~	~~Medium~~	~~The Transmission Owner failed to prevent vegetation from encroaching within the MVCD of a transmission line as described in R2.~~	~~The Transmission Owner incurred a Sustained Outage due to vegetation falling into a transmission line as described in R2 from within the Active Transmission Line ROW.~~	~~The Transmission Owner incurred a Sustained Outage due to the blowing together of vegetation and a transmission line as described in R2 from within the Active Transmission Line ROW.~~	~~The Transmission Owner incurred a Sustained Outage due to vegetation growing into a transmission line as described in R2.~~
~~R3~~		~~Long-Term Planning~~	~~Lower~~		~~The Transmission Owner has a documented transmission vegetation management program, but the transmission vegetation management program does not describe how work is conducted on the Active Transmission Line ROWs to avoid Sustained Outages due to vegetation.~~	~~The Transmission Owner has a documented transmission vegetation management program, but the transmission vegetation management program does not consider all possible locations the conductor may occupy assuming operation within Rating and Rated Electrical Operating Conditions~~	~~The Transmission Owner does not have a documented transmission vegetation management program.~~

~~R4~~	~~Real-time~~	~~Medium~~				~~The Transmission Owner had verified knowledge of a vegetation imminent threat condition and did not notify the responsible control center.~~
~~R5~~	~~Operations Planning~~	~~Medium~~				~~The Transmission Owner did not take interim corrective action when it was temporarily constrained from performing planned vegetation work where an applicable transmission line was put at potential risk.~~
~~R6~~	~~Operations Planning~~	~~High~~	~~The Transmission Owner inspected greater than 95% but less than 100% of the ROW as measured by applicable line miles (kilometers) (based on units of choice: circuit, pole line, ROW, etc.).~~	~~The Transmission Owner inspected greater than 90% but less than or equal to 95% of the ROW as measured by applicable line miles (kilometers) (based on units of choice: circuit, pole line, ROW, etc.).~~	~~The Transmission Owner inspected greater than 85% but less than or equal to 90% of the ROW as measured by applicable line miles (kilometers) (based on units of choice: circuit, pole line, ROW, etc.).~~	~~The Transmission Owner inspected less than or equal to 85% of the ROW as measured by applicable line miles (kilometers) (based on units of choice: circuit, pole line, ROW, etc.).~~
~~R7~~	~~Operations Planning~~	~~High~~	~~The Transmission Owner executed greater than 95% but less than 100% of its annual work plan as adjusted.~~	~~The Transmission Owner executed greater than 90% but less than or equal to 95% of its annual work plan as adjusted.~~	~~The Transmission Owner executed greater than 85% but less than or equal to 90% of its annual work plan as adjusted.~~	~~The Transmission Owner executed less than or equal to 85% of its annual work plan as adjusted.~~

~~Administrative Procedure~~

The Transmission Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of transmission lines determined by the Transmission Owner to have been caused by vegetation that includes, as a minimum, the following:~~:.~~

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable transmission lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the active transmission line~~Active Transmission Line~~ ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable transmission lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the active transmission line~~Active Transmission Line~~ ROW;
- Category 2 — Fall-ins: Sustained Outages caused by vegetation falling into applicable transmission lines from within the active transmission line~~Active Transmission Line~~ ROW;
- Category[3] 4 — Blowing together: Sustained Outages caused by vegetation and applicable transmission lines blowing together from within the active transmission line~~Active Transmission Line~~ ROW.

The Regional Entity will report the outage information provided by Transmission Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

[3] Category 3 reporting is eliminated.

At the request of the Standards Committee, stakeholders are asked to review and comment on the proposed VSLs for R1 and R2. Following the comment period and nonbinding poll, only one set of VSLs will move forward for R1 and R2.

Time Horizons, Violation Risk Factors, and Violation Severity Levels

Table 1						
R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1-SDT Version	Real-time	High	The Transmission Owner had an encroachment into the MVCD observed in real time, absent a Sustained Outage.	The Transmission Owner had an encroachment due to a fall-in from inside the active transmission line ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner had an encroachment due to blowing together of applicable lines and vegetation located inside the active transmission line ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner had an encroachment due to a grow-in that caused a vegetation-related Sustained Outage.
R1 Staff Version	Real-time	High			The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.	The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: • A fall-in from inside the active transmission line ROW • Blowing together of applicable lines and vegetation located inside the active transmission line ROW • A grow-in
R2-SDT Version	Real-time	Medium	The Transmission Owner had an encroachment into the MVCD observed in real time, absent a	The Transmission Owner had an encroachment due to a fall-in from inside the active transmission line	The Transmission Owner had an encroachment due to blowing together of applicable lines and vegetation located inside the	The Transmission Owner had an encroachment due to a grow-in that caused a vegetation-related Sustained Outage.

Table 1							
R#		Time Horizon	VRF	Violation Severity Level			
				Lower	Moderate	High	Severe
				Sustained Outage.	ROW that caused a vegetation-related Sustained Outage.	active transmission line ROW that caused a vegetation-related Sustained Outage.	
R2 Staff Version		Real-time	Medium			The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.	The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: • A fall-in from inside the active transmission line ROW • Blowing together of applicable lines and vegetation located inside the active transmission line ROW • A grow-in
R3		Long-Term Planning	Lower		The Transmission Owner has documented the procedures, processes, or specifications but does not incorporate the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency,	The Transmission Owner has documented the procedures, processes, or specifications but does not incorporate the dynamics of a transmission line conductor's movement throughout its Rating and Rated Electrical Operating Conditions, for the Transmission Owner's	The Transmission Owner does not have any documented procedures, processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the Transmission Owner's applicable lines.

Table 1							
R#	Time Horizon	VRF	Violation Severity Level				
			Lower	Moderate	High	Severe	
				for the Transmission Owner's applicable lines.	applicable lines.		
R4	Real-time	Medium			The Transmission Owner experienced a vegetation threat confirmed by qualified personnel and notified the control center holding switching authority for that transmission line, but there was intentional delay in that notification.	The Transmission Owner experienced a vegetation threat confirmed by qualified personnel and did not notify the control center holding switching authority for that transmission line.	
R5	Operations Planning	Medium				The Transmission Owner did not take corrective action when it was constrained from performing planned vegetation work where a transmission line was put at potential risk.	
R6	Operations Planning	Medium	The Transmission Owner failed to inspect 5% or less of the ROW as measured by applicable-line miles (kilometers) (based on units of choice: circuit, pole line, ROW, etc.).	The Transmission Owner failed to inspect more than 5% up to and including 10% of the ROW as measured by applicable-line miles (kilometers) (based on units of choice: circuit, pole line, ROW, etc.).	The Transmission Owner failed to inspect more than 10% up to and including 15% of the ROW as measured by applicable-line miles (kilometers) (based on units of choice: circuit, pole line, ROW, etc.).	The Transmission Owner failed to inspect more than 15% of the ROW as measured by applicable-line miles (kilometers) (based on units of choice: circuit, pole line, ROW, etc.).	
R7	Operations Planning	Medium	The Transmission Owner failed to complete up to 5% of its annual work plan (including modifications if any).	The Transmission Owner failed to complete more than 5% and up to 10% of its annual work plan (including modifications if	The Transmission Owner failed to complete more than 10% and up to 15% of its annual work plan (including modifications if any).	The Transmission Owner failed to complete more than 15% of its annual work plan (including modifications if any).	

Table 1							
R#	Time Horizon	VRF	Violation Severity Level				
			Lower	Moderate	High	Severe	
				any).			

Variances

None.

Interpretations

None.

Guidelines

~~Guideline~~ and Technical Basis

Requirements R1 and R2:

~~Requirements~~ R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the prevention of vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each ~~state that if a~~ Transmission Owner to prevent vegetation from encroaching within the Minimum Vegetation Clearance Distance of transmission lines. R1 is applicable to lines "identified as an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions) to avoid a Sustained Outage". R2 applies to all other applicable lines that are not an element of an IROL or Major WECC Transfer Path.

The separation of applicability (between R1 and R2) recognizes that an encroachment into the MVCD of an IROL or Major WECC Transfer Path transmission line is a greater risk to the electric transmission system. Applicable lines that are not an element of an IROL or Major WECC Transfer Path are required to be clear of vegetation but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

These requirements (R1 and R2) state that if vegetation encroaches ~~observes vegetation~~ within the distances prescribed in ~~FAC-003 –~~ Table 2, it is in violation of the standard. Table 2 delineates~~this Standard. The MVCD table contains~~ the distances necessary to prevent ~~which are required to ensure that~~ spark-over ~~will not occur; the distances are~~ based on the Gallet equations as described more fully in a supplemental *Transmission Vegetation Management Standard FAC-003-2 Technical Reference*.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating (potentially in violation of other standards), the occurrence of a clearance encroachment may occur. For example, emergency actions taken by a Transmission Operator or Reliability Coordinator to protect an Interconnection may cause the transmission line to sag more and come closer to vegetation, potentially causing an outage. Such vegetation-related outages are not a violation of these requirements.

Evidence of violation of Requirement~~. Requirements~~ R1 and R2 include real-time ~~refer to~~ observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the active transmission line ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to blowing together of applicable lines and vegetation located inside the active transmission line ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. If an investigation of a Fault by a qualified person confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered a Real-time~~in "real time". This means an actual field~~ observation. ~~or measurement of the conductor-to-vegetation distance and not a calculated determination of relative positions.~~

With this approach, the VSLs were defined such that they directly correlate to the severity of a failure to keep vegetation away from conductors and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the goal of "preventing a Sustained Outage that could lead to Cascading." Thus violation severity increases with a Transmission Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation, for example a limb that only partially breaks and intermittently contacts a conductor. Such events are considered to be a single vegetation-related Sustained Outage under the Standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will help prevent transmission outages. ~~The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below.~~

Requirement R3:

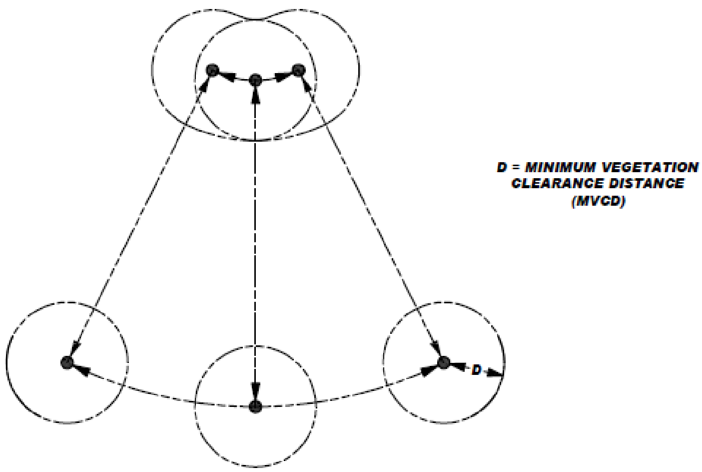
Requirement R3 is a competency based requirement concerned with the procedures, processes, or specifications, a Transmission Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the Transmission Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the Transmission System. The approach provides the basis for evaluating the intent, allocation of appropriate resources and the competency of the Transmission Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the Transmission Owner must be able to state what its approach is and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach a Transmission Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the Transmission Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing as a reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below.



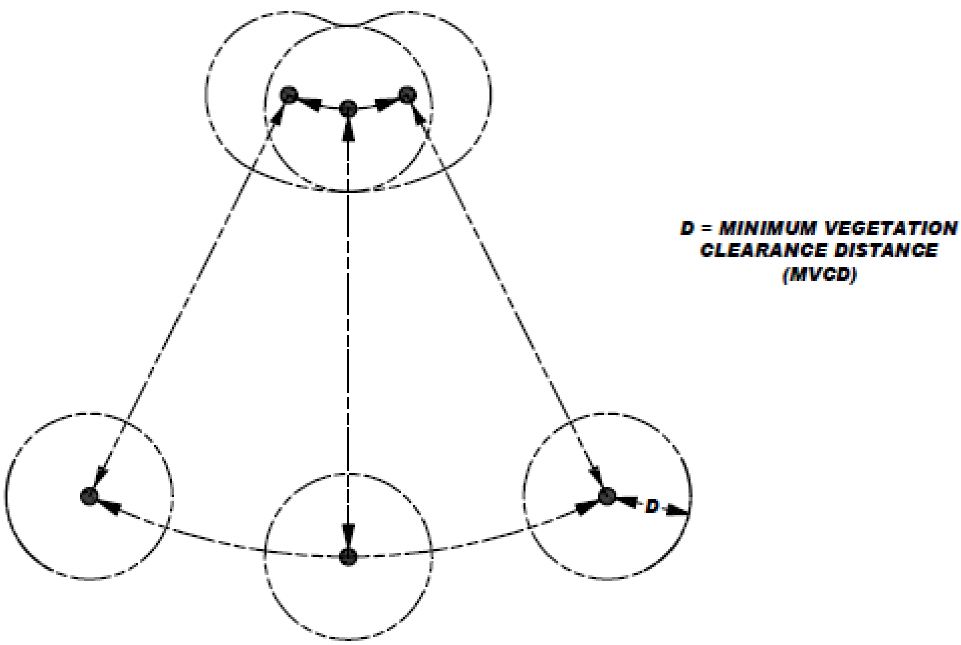


Figure 1

Cross-section view of a single conductor at a given point along the span showing six possible conductor positions due to movement resulting from thermal and mechanical loading.

Requirement R4:

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the Transmission Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a~~By complying with encroachment-prevention Requirements R1 and R2, together with the competency-based Requirement R3 (for a documented transmission vegetation management program), the Transmission Owner will have a cohesive vegetation management program for managing vegetation in such a manner as to maintain separation between conductors and vegetation. Additionally, an effective imminent threat process and interim corrective action plan strategies should be executed to be successful in meeting these requirements. The Transmission Owner's maintenance approach should result in vegetation never approaching the distances listed in the MVCD Table. However, brief encroachments by falling vegetation are not considered to be a violation.~~

~~In addition, the Transmission Owner should maintain detailed records of the findings of its planned inspections. This documentation constitutes evidence that the Transmission Owner had no encroachments into the MVCD Table distances.~~

~~These requirements assume that transmission lines are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its rating (potentially in violation of other standards), the occurrence of a clearance encroachment is not be a violation of this Standard. Conductor position, and the associated vegetation distance, that result from operation of a transmission line beyond its Rating (for example emergency actions taken by a TOP or RC to protect an Interconnection) is beyond the scope of this Standard.~~

~~**Requirement R3:**~~
~~An adequate transmission vegetation management program formally establishes the guidelines that are used by the Transmission Owner to plan and perform vegetation work that is necessary to prevent transmission outages and minimize risk to the Transmission System.~~

~~There may be many acceptable approaches to maintain clearances. However, the Transmission Owner should be able to state what its approach is and how it conducts work to maintain clearances. See Figure 1 for illustration of possible conductor locations.~~

~~**Requirement R4:**~~
~~The term "verified knowledge" implies reliable confirmation that an imminent~~ threat actually exists due to vegetation. This confirmation ~~Verification~~ could be in ~~that~~ the form of~~initial call-in came from~~ a qualified~~trained~~ employee who personally identifies~~able to identify~~ such a threat in the field. Confirmation ~~or it~~ could also be made~~verified~~ by sending out ~~such~~ a qualified~~trained~~ person to evaluate a situation reported by a landowner or an unqualified employee.~~confirm a call-in from a citizen.~~

Vegetation~~Two key elements of an acceptable imminent threat procedure are outlined below:~~
- ~~Specify the vegetation~~-related conditions that warrant a response ~~:~~

~~Examples of these vegetation-related conditions~~ include vegetation that is near or encroaching into the MVCD (a grow-in ~~growth~~ issue) or vegetation that could fall~~presents an imminent danger of falling~~ into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.~~)~~

- ~~Notify the appropriate operating authority:~~

The Transmission Owner has the responsibility to ensure the proper communication between field personnel and the control center~~operating authority~~ to allow the control center~~operating authority~~ to take the appropriate action until the vegetation threat is relieved.~~ ~~ Appropriate actions may include a temporary reduction in the line loading, ~~or~~ switching the line out of service, or positioning the system in recognition of the increasing risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).~~.~~

> ~~The protocol for contacting the operating authority should be defined. Some Transmission Owners' processes may require a call directly to the operating authority, while other Transmission Owners may require a call to a supervisor or field forester who will in turn notify the proper operating authority.~~
>
> ~~The term "responsible control center" refers to personnel with direct responsibility for operating the transmission lines, such as the Transmission Owner's control center, an Independent System Operator, or other operating entity. In the case where the operating authority is not the Transmission Operator the communication between the Transmission Operator and the operating authority will occur by the normal policies that govern their relationship.~~

~~The imminent threat process should be implemented in terms of minutes or hours as opposed to a longer time frame for interim corrective action plans (see R5).~~

All potential grow-in~~serious growth~~ or fall-in vegetation-related conditions will ~~are~~ not necessarily cause a Fault at any moment.~~considered imminent threats under this Standard.~~ For example, some Transmission Owners may have a danger tree identification program that identifies trees for removal ~~trees~~ with the potential to fall near the line. These trees would~~are~~ not require notification to~~necessarily considered imminent threats under~~ the control center~~Standard~~ unless they pose an immediate fall-in threat.

Requirement R5:

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the Transmission Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance.

~~There can be situations involving vegetation that are not considered vegetation-related imminent threats under this Standard. For example, a logging operation on or near the Active Transmission Line ROW can pose an immediate threat of a sustained outage and result in the initiation of an imminent threat process in the same manner as the presence of a nearby crane or the notification of a hot-spot on a conductor connector. Although the logging threat in this example tangentially involves vegetation, it is not considered a vegetation-related imminent threat under the Standard.~~

~~**Requirement R5:**~~

The intent of this requirement is to deal with situations that prevent the Transmission Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the Transmission Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential~~immediate~~ risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the Transmission Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the Transmission Owner is required to take ~~an interim~~ corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the Transmission Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to ~~immediately~~ mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for each location.

- In developing the specific action to mitigate the potential risk to the transmission line the Transmission Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The Transmission Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:

R6 is a risk-based requirement. This requirement sets a minimum time period for completing ~~the~~ Vegetation Inspections that fits general industry practice. In addition, the fact that Vegetation Inspections can be performed in conjunction with general line inspections further facilitates a Transmission Owner's ability to meet this requirement. However, the Transmission Owner may determine that more~~. More~~ frequent inspections are~~may be~~ needed to maintain reliability levels, dependent~~depending~~ upon such factors as anticipated growth rates of the local vegetation, length of the growing season for the geographical area, limited Active Transmission ROW width, and rainfall amounts. Therefore it is expected that some transmission~~some~~ lines may be designated with a higher frequency of inspections.

The VSL for Requirement R6 has VSL categories ranked by the percentage of the required ROW inspections completed. To calculate the percentage of inspection completion, the Transmission Owner ~~lines~~ may choose units such as: line miles or kilometers, circuit miles or kilometers, pole line miles, ROW miles, etc.

For example, when~~If~~ a Transmission Owner operates 2,000 miles of 230 kV transmission lines this Transmission Owner will be responsible for inspecting all 2,000 miles of 230 kV transmission lines at least once ~~line~~ during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect~~inspected~~ would be 100~~1900~~/2000 = 0.05~~95~~ or 5%.~~95%.~~ The "Low~~Lower~~ VSL" for R6 would apply in this example.

~~The standard allows Vegetation Inspections to be performed in conjunction with general line inspections as per the definition.~~

Requirement R7:

R7 is a risk-based requirement. The Transmission Owner is required to implement an annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a "span-by-span", or even a "line-by-line" detailed description of all work to be performed. It is only intended to require that the Transmission Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

The ability to modify the work plan allows ~~Documentation or other evidence of the work performed typically consists of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, work inspection reports and walk-through reports.~~

~~Documentation is required when the annual work plan is adjusted or not completely implemented as originally planned. The reasons for the deferrals or changes and the expected completion date of postponed work should be documented.~~

~~The flexibility to adjust the annual work plan must always ensure the reliability of the electric Transmission system. Flexibility is meant to address changing conditions of the vegetation on the Active Transmission Line ROW, emergencies, and other significant changing conditions.~~

~~This standard requires that the annual work plan be flexible to allow~~ the Transmission Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or~~.~~ ~~Another situational variance could be~~ a major storm could require redirecting~~that redirects~~ local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the Transmission Owner's system to work on another system. Any~~Examples~~ of these examples could result in acceptable~~documented adjustments may include~~ deferrals or additions to the annual work plan. Modifications to the annual work plan must always ensure the reliability of the electric Transmission system.

In general, the
~~The work plan is not intended to be a "span-by-span" detailed description of all work to be performed. It is intended to require the Transmission Owner to annually plan and schedule vegetation work to prevent encroachment into the MVCD.~~

~~The Transmission Owner is required to implement the annual work plan for~~ vegetation management ~~to accomplish the purpose of this standard. This means that vegetation~~ maintenance approach should use~~ought to be performed to~~ the full extent of the Transmission Owner's easement, fee simple and other legal rights~~. It is intended to address the importance of maintaining all locations on the Active Transmission Line ROWs for reliability purposes in lieu of making special exceptions.~~

- ~~Property owners and other interested parties occasionally request special considerations to leave undesirable vegetation conditions. Such considerations must never be~~ allowed. ~~to impact reliability.~~
- ~~These undesirable vegetation conditions require more frequent work or inspections than other locations with similar vegetation threats and similar easement rights which are not subject to the special property owner requests.~~
- ~~The Transmission Owner's vegetation maintenance work necessary to implement the annual work plan is most effective when performed to the maximum extent allowed by any easement, fee simple and other legal rights.~~
- ~~The Transmission Owner should, therefore, endeavor to maintain its Active Transmission Line ROW to the full extent of its legal rights at all times and in all cases.~~

A comprehensive approach that exercises the full extent of legal rights on the active transmission line ROW is superior to incremental management in the long term because it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient. ~~at all locations on the Active Transmission Line ROW .~~

When developing the annual work plan the Transmission Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Transmission Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the Transmission Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned

versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

~~The following conditions may result in adjustments to the annual work plan: abnormal weather such as drought, major storms, excessive rainfall, other environmental conditions such as infestation, disease, fire, etc. These conditions may be found as part of a special or scheduled Vegetation Inspection. Examples of annual work plan adjustments that are permitted may include revising the work plan priorities, rescheduling work to another time or selecting alternate vegetation control methods. Changes in land usage made by a property owner, such as timber clearing, may be another condition that warrants an adjustment.~~

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[4]
For **Alternating Current** Voltages

(AC) Nominal System Voltage (kV)	**(AC) Maximum System Voltage (kV)**	**MVCD feet (meters) sea level**	**MVCD feet (meters) 3,000ft (914.4m)**	**MVCD feet (meters) 4,000ft (1219.2m)**	**MVCD feet (meters) 5,000ft (1524m)**	**MVCD feet (meters) 6,000ft (1828.8m)**	**MVCD feet (meters) 7,000ft (2133.6m)**	**MVCD feet (meters) 8,000ft (2438.4m)**	**MVCD feet (meters) 9,000ft (2743.2m)**	**MVCD feet (meters) 10,000ft (3048m)**	**MVCD feet (meters) 11,000ft (3352.8m)**
765	800	8.06ft (2.46m)	8.89ft (2.71m)	9.17ft (2.80m)	9.45ft (2.88m)	9.73ft (2.97m)	10.01ft (3.05m)	10.29ft (3.14m)	10.57ft (3.22m)	10.85ft (3.31m)	11.13ft (3.39m)
500	550	5.06ft (1.54m)	5.66ft (1.73m)	5.86ft (1.79m)	6.07ft (1.85m)	6.28ft (1.91m)	6.49ft (1.98m)	6.7ft (2.04m)	6.92ft (2.11m)	7.13ft (2.17m)	7.35ft (2.24m)
345	362	3.12ft (0.95m)	3.53ft (1.08m)	3.67ft (1.12m)	3.82ft (1.16m)	3.97ft (1.21m)	4.12ft (1.26m)	4.27ft (1.30m)	4.43ft (1.35m)	4.58ft (1.40m)	4.74ft (1.44m)
230	242	2.97ft (0.91m)	3.36ft (1.02m)	3.49ft (1.06m)	3.63ft (1.11m)	3.78ft (1.15m)	3.92ft (1.19m)	4.07ft (1.24m)	4.22ft (1.29m)	4.37ft (1.33m)	4.53ft (1.38m)
161*	169	2ft (0.61m)	2.28ft (0.69m)	2.38ft (0.73m)	2.48ft (0.76m)	2.58ft (0.79m)	2.69ft (0.82m)	2.8ft (0.85m)	2.91ft (0.89m)	3.03ft (0.92m)	3.14ft (0.96m)
138*	145	1.7ft (0.52m)	1.94ft (0.59m)	2.03ft (0.62m)	2.12ft (0.65m)	2.21ft (0.67m)	2.3ft (0.70m)	2.4ft (0.73m)	2.49ft (0.76m)	2.59ft (0.79m)	2.7ft (0.82m)
115*	121	1.41ft (0.43m)	1.61ft (0.49m)	1.68ft (0.51m)	1.75ft (0.53m)	1.83ft (0.56m)	1.91ft (0.58m)	1.99ft (0.61m)	2.07ft (0.63m)	2.16ft (0.66m)	2.25ft (0.69m)
88*	100	1.15ft (0.35m)	1.32ft (0.40m)	1.38ft (0.42m)	1.44ft (0.44m)	1.5ft (0.46m)	1.57ft (0.48m)	1.64ft (0.50m)	1.71ft (0.52m)	1.78ft (0.54m)	1.86ft (0.57m)
69*	72	0.82ft (0.25m)	0.94ft (0.29m)	0.99ft (0.30m)	1.03ft (0.31m)	1.08ft (0.33m)	1.13ft (0.34m)	1.18ft (0.36m)	1.23ft (0.37m)	1.28ft (0.39m)	1.34ft (0.41m)

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above).

[4] The distances in this Table are the minimums required to prevent Flashover~~flashover~~; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

Table 2 (cont.) — Minimum Vegetation Clearance Distances (MVCD)
For **Direct Current** Voltages

(DC) Nominal Pole to Ground Voltage (kV)	MVCD feet (meters) sea level	MVCD feet (meters) 3,000ft (914.4m) Alt.	MVCD feet (meters) 4,000ft (1219.2m) Alt.	MVCD feet (meters) 5,000ft (1524m) Alt.	MVCD feet (meters) 6,000ft (1828.8m) Alt.	MVCD feet (meters) 7,000ft (2133.6m) Alt.	MVCD feet (meters) (8,000ft (2438.4m) Alt.	MVCD feet (meters) 9,000ft (2743.2m) Alt.	MVCD feet (meters) 10,000ft (3048m) Alt.	MVCD feet (meters) 11,000ft (3352.8m) Alt.
±750	13.92ft (4.24m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.9ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.07ft (3.07m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	(13.54ft 4.13m)
±500	7.89ft (2.40m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	4.78ft (1.46m)	5.35ft (1.63m)	5.55ft (1.69m)	5.75ft (1.75m)	5.95ft (1.81m)	6.15ft (1.87m)	6.36ft (1.94m)	6.57ft (2.00m)	6.77ft (2.06m)	6.98ft (2.13m)
±250	3.43ft (1.05m)	4.02ft (1.23m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5ft (1.52m)	5.17ft (1.58m)

Table 3 – Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW

69 - 138 kV	37.5 ft.
139 - 230 kV	50 ft.
231 - 345 kV	75 ft.
346 - 500 kV	87.5 ft.
501 - 765 kV	100 ft.

Implementation Plan for FAC-003-2

Prerequisite Approvals
There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

FAC-003-2 – Vegetation Management

Revision to Sections of Approved Standards and Definitions
There are no proposed revisions to requirements in other already approved standards. There is a revised definition in the proposed standard. FAC-003-1 will be retired when FAC-003-2 becomes effective.

Compliance with Standard
The standard applies to Transmission Owners.

Effective Date
The effective date is the date entities are expected to meet the performance identified in this standard. The effective date allows entities time to make revisions to their existing transmission vegetation management programs to comply with the new requirements.

1. First calendar day of the first calendar quarter one year after applicable regulatory authority approval for all requirements
2. First calendar day of the first calendar quarter one year following Board of Trustees adoption unless governmental authority withholds approval
3. First calendar day of the first calendar quarter that is at least one year following Board of Trustees adoption

Exceptions:

A line operated below 200kV, designated by the Planning Coordinator as an element of an IROL or as a Major WECC transfer path, becomes subject to this standard 12 months after the date the Planning Coordinator or WECC initially designates the line as being subject to this standard.

An existing transmission line operated at 200kV or higher that is newly acquired by an asset owner and was not previously subject to this standard, becomes subject to this standard 12 months after the acquisition date of the line.

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Implementation Plan for FAC-003-2

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

FAC-003-2 ~~—~~ – Vegetation Management

Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards. There is a revised definition in the proposed standard. FAC-003-1 will be retired when FAC-003-2 becomes effective.

~~When FAC-003-2 is approved, a new definition for Active Transmission Line Right-of-Way and a revised definition for Vegetation Inspection should become effective.~~

~~The original definition of Vegetation Inspection should be retired when the new definition becomes effective.~~

~~FAC-003-1 will be retired when FAC-003-2 becomes effective.~~

Compliance with Standard

The standard applies to Transmission Owners.

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Effective Date

The effective date is the date entities are expected to meet the performance identified in this standard. The effective date allows entities time to make revisions to their existing transmission vegetation management programs to comply with the new requirements.

~~Requirement~~	~~Jurisdiction~~									
	~~Alberta~~	~~British Columbia~~	~~Manitoba~~	~~New Brunswick~~	~~Newfound-land~~	~~Nova Scotia~~	~~Ontario~~	~~Quebec~~	~~Saskatch-ewan~~	~~USA~~
~~R1~~	~~1~~	~~1~~	~~1~~	~~3~~	~~TBD~~	~~TBD~~	~~2~~	~~TBD~~	~~1~~	~~1~~
~~R2~~	~~1~~	~~1~~	~~1~~	~~3~~	~~TBD~~	~~TBD~~	~~2~~	~~TBD~~	~~1~~	~~1~~
~~R3~~	~~1~~	~~1~~	~~1~~	~~3~~	~~TBD~~	~~TBD~~	~~2~~		~~1~~	~~1~~
~~R4~~	~~1~~	~~1~~	~~1~~	~~3~~	~~TBD~~	~~TBD~~	~~2~~	~~TBD~~	~~1~~	~~1~~
~~R5~~	~~1~~	~~1~~	~~1~~	~~3~~	~~TBD~~	~~TBD~~	~~2~~	~~TBD~~	~~1~~	~~1~~
~~R6~~	~~1~~	~~1~~	~~1~~	~~3~~	~~TBD~~	~~TBD~~	~~2~~	~~TBD~~	~~1~~	~~1~~
~~R7~~	~~1~~	~~1~~	~~1~~	~~3~~	~~TBD~~	~~TBD~~	~~2~~	~~TBD~~	~~1~~	~~1~~

1. First calendar day of the first calendar quarter one year after applicable regulatory authority approval for all requirements
2. First calendar day of the first calendar quarter one year following Board of Trustees adoption unless governmental authority withholds approval
3. First calendar day of the first calendar quarter that is at least one year following Board of Trustees adoption

Exceptions:

~~Lines~~A line operated below 200kV, designated by the Planning Coordinator as an element of an IROL or as a Major WECC ~~Transfer Path, become~~transfer path, becomes subject to this standard 12 months after the date the Planning Coordinator or WECC initially designates the ~~lines~~line as being subject to this standard.

An existing transmission line operated at 200kV or higher that is newly acquired by an asset owner and was not previously subject to this standard, becomes subject to this standard 12 months after the acquisition date of the line~~(s).~~.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Unofficial Comment Form for 4th Draft of FAC-003-2 Transmission Vegetation Management —Project 2007-07 Vegetation Management

Please **DO NOT** use this form to submit comments. Please use the electronic form located at the site below to submit comments on the 4th Draft of FAC-003-2 Transmission Vegetation Management. Comments must be submitted by**, July 18, 2010**

http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

If you have questions please contact Harry Tom at Harry.Tom@nerc.net or by telephone at (860) 550-4157.

Background Information

The purpose of Project 2007-07 Vegetation Management is to:

- Assist in providing an adequate level of reliability for the North American electric Transmission System by verifying that the FAC-003-2 Transmission Vegetation Management standard is complete and that its requirements are set at an appropriate level to ensure reliability.
- Incorporate other general improvements described in the Standard Review Guidelines to bring FAC-003-2 Transmission Vegetation Management into conformance with the latest version of the Reliability Standards Development Procedure and the ERO Sanctions Guidelines.
- Consider comments received from ERO regulatory authorities and stakeholders on FAC-003-1 Transmission Vegetation Management as noted in the NERC Standards Issues Database.
- Satisfy the requirement for review of FAC-003-2 Transmission Vegetation Management within five-year review cycle.

In addition, on January 14, 2010, the NERC Standards Committee endorsed the use of Project 2007-07 Vegetation Management as the prototype for the proof-of-concept for using the results-based criteria for developing a reliability standard. The results-based initiative is intended to focus the collective effort of NERC and industry participants on improving the clarity and quality of NERC reliability standards by developing performance-based, risk-based and competency-based requirements that accomplish a reliability objective through a defense-in-depth strategy, while eliminating documentation-driven requirements that do not have an impact on bulk power system reliability.

The first draft of the revised standard was posted in a 'new' format from March 1-31, 2010 for an 'informal' comment period.

A summary of the SDT considerations for the responses to the March 1, 2010 submittal has been posted on the NERC website in lieu of a full Consideration of Comments Report.

Note-worthy modifications incorporated into this draft 4 of FAC-003-2 Transmission Vegetation Management include:

- Replaced the defined term "Active Transmission Line Right of Way" with footnote number 2 that provides a description of "active transmission line ROW" and added Table 3, "*Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW*" to support that description.

- Terminology changes in the "Force Majeure" statement related to the terms "reasonable" and "human activity"
- Terminology changes to Measures M1 and M2 related to observation in real time and the investigation of Faults.
- Changes to Requirement R3 to incorporate the various terms the industry uses for program documentation, and further changes to R3 that address the nature of the mutually dependent variables that can drive different approaches to vegetation maintenance.
- Clarifying verbiage in Requirement R4.
- Removal of the term "flexible" in R7
- Footnote changes for clarification to Table 2

The following questions will assist the SDT in finalizing the development of FAC-003-2 Transmission Vegetation Management. In addition, question #7, relative to Violation Severity Levels, has been included at the direction of the Standards Committee.

For questions where you agree with indicated statement, please state that you agree and if able, please provide supporting documentation. If you disagree with the statement, please explain why you disagree and provide a rationale to support your position. We would appreciate responses to as many of the following questions as possible.

1. The SDT replaced the defined term "Active Transmission Line Right of Way" with footnote number 2 that provides a description of "active transmission line ROW" and added Table 3, "*Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW*" to support that description. Do you agree? Please explain.

   ☐ Yes
   ☐ No
   Comments:

2. In response to comments received regarding the terms "reasonable" and "human errors/human activity", the SDT modified the Other Section and Background Section. Do you agree? Please explain.

   ☐ Yes
   ☐ No
   Comments:

3. In response to comments received regarding the language in M1 and M2, the SDT modified the first bulleted item and added a sentence to the end of the paragraph in M1 and M2. Do you agree? Please explain.

   ☐ Yes
   ☐ No
   Comments:

4. In response to comments received that requirement R3 is deficient in detail, the SDT modified the requirement. Do you agree? Please explain.

   ☐ Yes
   ☐ No

Comments:

5. In response to comments received that requirement R7 is unclear with respect to flexible work plans, the SDT modified the requirement. Do you agree? Please explain.

☐ Yes

☐ No

Comments:

6. In response to comments received that requirement R1/R2 may not adequately protect the transmission conductors under all conditions of sag and sway, the SDT drafted alternate language for the industry to provide feedback. The SDT did not opt to incorporate this language into "Draft 4" until further comment was solicited from industry. Which do you prefer? Please comment on your choice in the comment box below:

*"**Alternate R1/R2.** Each Transmission Owner shall manage the floor of its Active Transmission Line ROW in accordance to one of the following at all times:*

A) A fixed maximum vegetation height of 15 feet from the ground at the mid-half of the span and 20 feet in the outside quarters of the span, or,

B) A calculated maximum vegetation height that is the difference between the minimum conductor height at "max sag" minus MVCD minus cycle growth, or,

C) A calculated minimum vegetation to conductor clearance that is the sum of "max sag" in the span plus MVCD plus cycle growth, or,

D) A value determined by the Transmission Owner to provide a separation between the conductor and the vegetation that is comparable to options A, B, or C.

E) Any alternative approach that ensures no encroachment occurs within MVCD, considering the sag and sway of the conductor throughout its operating range under rated conditions.

F) A value to provide a separation between the conductor and the vegetation that is the sum of MVCD, and a value that considers the sag and sway of the conductor throughout its operating range under rated conditions plus 10 feet."

NOTE: The SDT suggests similar language as found in the posted draft for measures M1/M2 may be appropriate with this alternate R1/R2.

☐ Draft 4 version of R1/R2

☐ Alternate version of R1/R2

Comment:

7. The drafting team and NERC staff disagree on an appropriate set of VSLs for Requirements R1 and R2 and the Standards Committee has directed that both sets of VSLs be posted for stakeholder comments.

The drafting team has proposed the following VSLs for R1 and R2:

VSLs for R1 and R2 Proposed by the VM SDT				
R#	**Lower**	**Moderate**	**High**	**Severe**
R1 VM SDT	The Transmission Owner had an encroachment into the MVCD observed in real time, absent a Sustained Outage.	The Transmission Owner had an encroachment due to a fall-in from inside the active transmission line ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner had an encroachment due to blowing together of applicable lines and vegetation located inside the active transmission line ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner had an encroachment due to a grow-in that caused a vegetation-related Sustained Outage.
R2 VM SDT	The Transmission Owner had an encroachment into the MVCD observed in real time, absent a Sustained Outage.	The Transmission Owner had an encroachment due to a fall-in from inside the active transmission line ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner had an encroachment due to blowing together of applicable lines and vegetation located inside the active transmission line ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner had an encroachment due to a grow-in that caused a vegetation-related Sustained Outage.

VSLs for R1 and R2 Proposed by the VM SDT

The SDT assigned VSLs for R1 and R2 in accordance with its interpretation of the VSL Guidelines. To support that interpretation, the SDT cites page 3 of the VSL Guideline as justification. The VSL Guideline states that for – "Requirements with Parts that Contribute Unequally to the Requirement: If a requirement has several parts, and the parts contribute unequally to the reliability-related objective of the requirement, then noncompliance with each of the parts should be clearly associated with at least one of the VSLs."

The VSL Guidelines also goes on to say, "Requirements with Wide Range of Noncompliant Performance: If a requirement has a wide range of noncompliant performance that at least partially meets the intent of the requirement, then that requirement should have multiple VSLs. There are many different ways of developing VSLs to categorize different degrees of noncompliant performance. A set of VSLs developed should collectively address all of the elements in the requirement. Thus, if a requirement includes both specific actions and a timeframe for completion of those actions, then the VSLs should address noncompliance with both the completeness of the actions and the timeliness of those actions. Not all VSLs need to address both components of the requirement, but collectively the set of VSLs must address all aspects of the requirement." The SDT asserts that for Requirement R1 there is indeed a wide range of possible noncompliance for a failure to manage vegetation. Examples could include failure to manage vegetation along an entire line, failure to manage the floor of the right of way, failure to manage the edges of the right of way, or a failure to manage a single tree out of an otherwise-well-managed right of way.

The SDT points to the reliability objectives contained in requirements R1 and R2. The Transmission Owner is required to manage vegetation to prevent encroachments within the MVCD that could lead to Sustained Outages. These objectives address different degrees or types of vegetation encroachments and associated reliability results. For example, not all encroachments lead to Sustained Outages. Moreover, there is an operational differentiation between a fall-in, blow-together or grow-in event. A fall-in has never been known to cause a cascading outage. Therefore the team feels that a Lower VSL is appropriate. A blowing-together-caused fault is somewhat more egregious than a fall-in, as it has the potential for re-occurring and is therefore assigned a Higher VSL. A grow-in from vegetation on the active ROW that causes a sustained outage, on the other hand, has been the only known cause for the initiation of cascading outages to date in North America and this type of vegetation should be appropriately addressed by a Transmission Owner; thus the Severe VSL. For these reasons the SDT feels that the VSL assignments are appropriate.

VSLs for R1 and R2 Proposed by NERC Staff

The Standards Staff is concerned that the VSLs proposed by the VM SDT seem to be based on the likelihood that a violation of the requirement will result in a sustained outage – not in the degree to which the entity violated the requirement. As such, the VSLs developed by the VM SDT don't support NERC's VSL Guidelines. Both R1 and R2 require the responsible entity to ". . . manage vegetation to prevent encroachment that could result in a Sustained Outage . . ." Thus, any sustained outage associated with vegetation-related encroachment into the MVCD totally misses the intent of the requirement and meets the criteria for a Severe VSL. The drafting team's proposed VSL would assign some vegetation-related sustained outages of transmission lines as "moderate" or "high" VSLs.

NERC's VSL Criteria			
Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

The Standards Staff proposes the following VSLs:

VSLs for R1 and R2 Proposed by NERC Staff				
R#	Lower	Moderate	High	Severe
R1 NERC Staff	Not applicable.	Not applicable.	The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.	The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: • A fall-in from inside the active transmission line ROW • Blowing together of applicable lines and vegetation located inside the active transmission line ROW • **A grow-in**

VSLs for R1 and R2 Proposed by NERC Staff				
R#	**Lower**	**Moderate**	**High**	**Severe**
R2 NERC Staff	Not applicable.	Not applicable.	The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.	The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following: • A fall-in from inside the active transmission line ROW • Blowing together of applicable lines and vegetation located inside the active transmission line ROW • **A grow-in**

Which set of proposed VSLs best supports NERC's VSL Criteria?

☐ VSLs proposed by the VM SDT

☐ VSLs proposed by NERC staff

Comments:

8. Is there anything that you have not addressed above regarding the draft FAC-003-2 Transmission Vegetation Management standard or the Technical Reference Document? If yes, please provide what you believe should be changed, added or deleted and the rationale for your proposal.

☐ Yes

☐ No

Comments:

FAC-003-1 Mapping to Proposed NERC Reliability Standard FAC-003-2 RBS Draft 4

Standard FAC-003-1	Comment	Proposed Standard FAC-003-2 RBS Draft 4
Standard Development Roadmap	Modified per proposed SCPSC format for RBS	**Standard Development Timeline**
Definitions of Terms Used in Standard	During the first comment period, the SDT received several comments noting that many utilities typically combine the vegetation inspection with other maintenance inspections. Due to the comments, the SDT proposed a modified Vegetation Inspection definition to document the acceptability of this industry practice. As noted in the "Guidelines and Technical Basis" section, this broader definition facilitates a Transmission Owner's ability to meet the requirement and the added clarification aides compliance understanding to meet Requirement 6.	**Definitions of Terms Used in Standard** **Vegetation Inspection** The systematic examination of vegetation conditions on a maintained transmission line Right-of-Way which may be combined with a general line inspection. The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently. Current definition of Vegetation Inspection: The systematic examination of a transmission corridor to document vegetation conditions.
Effective Dates **5. Effective Dates:** **5.1.** One calendar year from the date of adoption by the NERC Board of Trustees for Requirements 1 and 2. **5.2.** Sixty calendar days from the date of adoption by the NERC Board of Trustees for Requirements 3 and 4.	In order to fully implement any new standard or requirement it is necessary to factor in a reasonable transitional period. As with the current version of FAC-003, the proposed version allows a reasonable time period before the standard is fully applicable. In addition to standardizing the implementation date to coincide with the beginning of a calendar month, the new version improves upon the current standard by recognizing that new lines may be added by the Planning Coordinator at any given time in the future. These new lines will necessarily require an extended effective date before the standard is applicable.	**Effective Dates** 1. First calendar day of the first calendar quarter one year after applicable regulatory authority approval for all requirements 2. First calendar day of the first calendar quarter one year following Board of Trustees adoption unless governmental authority withholds approval 3. First calendar day of the first calendar quarter that is at least one year following Board of Trustees adoption Exceptions: A line operated below 200kV, designated by the Planning Coordinator as an element of an IROL or as a Major WECC transfer path, becomes subject to this standard 12 months after the date the Planning Coordinator or WECC initially designates the lines as being subject to this standard. An existing transmission line operated at 200kV or higher that is newly acquired by an asset owner and was not previously subject to this standard, becomes subject to this standard 12

Standard FAC-003-1	Comment	Proposed Standard FAC-003-2 RBS Draft 4
		months after the acquisition date of the line.
1. Title: Transmission Vegetation Management Program		**1. Title:** Transmission Vegetation Management
2. Number: FAC-003-1		**2. Number:** FAC-003-2
3. Purpose: To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation related outages of the transmission systems to the respective Regional Reliability Organizations (RRO) and the North American Electric Reliability Council (NERC).	The SDT tightened up the Purpose statement to remove unnecessary wording and to remove redundant verbiage also contained in the Applicability section. The SDT also removed from the Purpose any mention of the reporting of vegetation-caused outages, in part because the Standard no longer requires reporting of outages due to vegetation falling from outside the right of way. The new, shorter Purpose statement is more goal-oriented as a Purpose statement should be, instead of containing rambling verbiage that re-states tasks and activities covered elsewhere in the Applicability or Requirements. The new Purpose statement is better because it provides clarity to industry stakeholders that only a narrow class of vegetation issues lead to large-scale blackouts. For instance, no cascading-style outage – anytime or anywhere – has ever been caused by a tree falling into a transmission line. This Purpose statement appropriately focuses the Standard's requirements on the areas of vegetation management that pose significant risk of cascading blackouts.	**3. Objective:** To improve the reliability of the electric Transmission system by preventing those vegetation related outages that could lead to Cascading.
4. Applicability: **4.1.** Transmission Owner **4.2.** Regional Reliability Organization **4.3.** This Standard shall apply to all transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RRO as critical to the reliability of the electric system in the region.	The Drafting team divided the Applicability section into two parts (entity and facility) in order to provide structural clarity. This improvement in readability makes this structure better than that existing in Version 1. In the Functional Entity section, the team removed the RRO as directed by FERC since the RRO(s) have no Requirement compliance responsibilities. Additionally, the data reporting which was why the RRO had been included in this section, is no longer a Requirement.	**4. Applicability:** **4.1.** Functional Entities: **4.1.1** Transmission Owners **4.2.** Facilities: Defined below, including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities: **4.2.1.** Transmission lines operated at 200kV

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies"*

Standard FAC-003-1	Comment	Proposed Standard FAC-003-2 RBS Draft 4
	In the Facility section, the team added specific references to specific land types on which Transmission rights-of-way may exist. This change was made to make it clear where the Standard applies in response to industry comments indicating confusion with the existing Standard which did not specifically address the issue. This addition is an improvement from Version 1 since the issue will now be clearly addressed. Additionally, the team modified the entity to identify sub-200 kV lines which are covered by this standard. In keeping with the removal of the RRO from the Standards, the team received valuable input from industry and FERC staff. It became clear that for the time horizon needed for the activities associated with vegetation management, the Planning Coordinator had the appropriate wide-area view and time horizon. FERC staff expressed a strong preference for NERC standards to be consistent in the determination of sub-200 kV lines that are sufficiently important to be covered by this standard and others that have the 200 kV bright lines. Thus the team chose to use an existing identification process (found in Standard FAC-014). These changes make this version much better than Version 1 because a responsible entity has been identified and an already FERC-approved NERC Standard process replaces an undefined process in Version 1. The FERC Order also outlined that NERC should determine if the identification “net” caught all the sub-200 kV lines of importance. The Drafting team identified that WECC has developed a classification of lines that have importance to the Western Interconnection. Therefore, the Drafting team added those lines. This addition makes this version better than Version 1 by including important lines that might otherwise be potentially omitted. Finally, the Drafting team added the exclusions in 4.2.4 in response to significant industry comments for clarity in interpretation and implementation of the standard. The ambiguity of the existing Standard has led to confusion in industry and in compliance. This addition makes this version better than Version 1 because it clearly describes which facilities are applicable which will eliminate the confusion.	or higher. **4.2.2.** Overhead transmission lines operated below 200kV having been identified as included in the definition of an Interconnection Reliability Operating Limit (IROL) under NERC Standard FAC 014 by the Planning Coordinator. **4.2.3.** Overhead transmission lines operated below 200 kV having been identified as included in the definition of one of the *Major WECC Transfer Paths in the Bulk Electric System*. **4.2.4.** This Standard does not apply to Facilities identified above (4.2.1 through 4.2.3) located in the fenced area of a switchyard, station or substation.

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		4.3. Enforcement: *The reliability obligations of the applicable entities and facilities are contained within the technical requirements of this standard. [Straw proposal]*
	Vegetation-related Sustained Outages that occur due to natural disasters are beyond the control of the Transmission Owner. These events are not classified as vegetation-related Sustained Outages and are therefore exempt from the Standard. Transmission lines are not designed to withstand the impacts of natural disasters such as flood, drought, earthquake, major storms, fire, hurricane, tornado, landslides, ice storms, etc. In the aftermath of catastrophic system damage from natural disasters the Transmission Owner's focus is on electric system restoration for public safety and critical support infrastructure. Sustained Outages due to human or animal activity are beyond the control of the Transmission Owner. These outages are not classified as vegetation-related Sustained Outages and are therefore exempt from the Standard. Examples of these events may include new plantings by outside parties of tall vegetation under the transmission line planted since the last Vegetation Inspection, tree contacts with line initiated by vehicles, logging activities, etc. This clarification of which outages are not applicable is an improvement to the language in requirement R3.2 in Version 1 and maintains the same level of reliability. The term "active transmission line ROW" as defined in footnote 2 is included to differentiate between Sustained Outages caused by vegetation growing either within or outside the ROW. This is in contrast to the version I definition of a simple ROW. This change is important because all Sustained Outages from vegetation growing on the ROW are violations of the Standard while all "off-ROW" Sustained Outages are not. The inclusion of the active transmission line ROW definition aids in compliance reporting and monitoring and helps Transmission Owner's implement their ROW management programs. This clarification places a	**4.4. Other:** This Standard does not apply to any occurrence, non-occurrence, or other set of circumstances that are beyond the control of a Transmission Owner subject to this reliability standard, including acts of God, flood, drought, earthquake, major storms, fire, hurricane, tornado, landslides, ice storms, vehicle contact with tree, human activity involving: removal of, installation of, or digging around vegetation, animals severing trees, lightning, epidemic, strike, war, riot, civil disturbance, sabotage, vandalism, terrorism, wind shear, or fresh gale (or higher wind speed) that restricts or prevents performance to comply with this reliability standard's requirements. Nothing in this section should be construed to limit the Transmission Owner's right to exercise its full legal rights on the active transmission line ROW[2] [2] A strip or corridor of land that is occupied by active transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities. However, it is not to be less than the width of the easement itself unless the easement exceeds distances as shown in Table 3 for various voltage classes.

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	minimum limit on the distance between the circuit and the ROW edge for use on ROW's where a transmission Owner has excessive ROW width that is far wider then is typically managed for that voltage class.	
	Added new section titled, "Background" per SCPSC format.	**5. Background** This NERC Vegetation Management Standard ("Standard") uses a defense-in-depth approach to improve the reliability of the electric Transmission system by preventing those vegetation related outages that could lead to Cascading. This Standard is…
R1. The Transmission Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the Transmission Owner's objectives, practices, approved procedures, and work specifications**1**. **R1.1.** The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the Transmission Owner's transmission lines. **R1.2.** The Transmission Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the Transmission Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and	R1 and its five subparts outlining the TVMP have been replaced by R1, R2, R3, R4, R5 and R6. R1 in Version 1 is a documentation requirement defining what should be in a TVMP. The requirements in Version 2 were crafted to be "results based" that define the desired end result and not necessarily the route to get to the end result. The TVMP document in version 1 is replaced by the competency requirement R3 in version 2. The TO must demonstrate that it understands the complex relationship of conductor movement under thermal load and wind and a vegetation growing and moving in proximity to the line. In version 1 the TO can simply state that it mows or trims and what its Clearance 1 and 2 is. In version 2, the TO must define the concepts used by an inspector or a tree crew in making decisions about which tree needs maintenance and how much should be removed. The improvement is that the TO's documentation can be evaluated to specific construction and maintenance standards. R1.1 has been moved to R6. It requires that each line be inspected annually and clarifies, through the definition of a Vegetation Inspection, that these inspection may be part of a broader line inspection. This improvement takes out the ambiguity of the frequency of inspections. R1.2 in version 1 requires that the TO document Clearances 1 and 2. The results based requirements in R1 and R2 in version 2 require that the TO achieve conductor to vegetation separation by preventing encroachments into MVCD, a clearance defining "spark-	**R1.** Each Transmission Owner shall manage vegetation to prevent encroachment that could result in a Sustained Outage of any line identified as an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions). Types of encroachment include: 1. An encroachment into the Minimum Vegetation Clearance Distance (MVCD) as shown in Table 2, observed in real time, absent a Sustained Outage, 2. An encroachment due to a fall-in from inside the active transmission line ROW that caused a vegetation-related Sustained Outage, 3. An encroachment due to blowing together of applicable lines and vegetation located inside the active transmission line ROW that caused a vegetation-related Sustained Outage, 4. An encroachment due to a grow-in that caused a vegetation-related Sustained Outage. **R2**. Each Transmission Owner shall manage vegetation to prevent encroachment that could result in a Sustained Outage of applicable lines that are not elements of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions). Types of encroachment include:

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maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors. **R1.2.1.** Clearance 1 — The Transmission Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below. **R1.2.2.** Clearance 2 — The Transmission Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These Transmission Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-	over" distances derived scientifically from the Gallet equations. FERC, in order 693, along with several commenters questioned the use of the MAID tables in Version 1. Version 2 offers appropriate clearances that are based in science. In addition, there are separate requirements for lines that could be part of an IROL/WECC transfer path event and those that are not. This allows for different Violation Risk Factors. R1.3 of Version1 required that personnel in the TVMP be qualified. The requirement did not clearly specify what the qualification would be and left it up to the TO. This is considered a 'fill in the blank' requirement and was eliminated. R1.4 in version 1 required the TO to have a mitigation plan where clearances could not be attained. This is replaced in Version 2 by R5. The new wording resolves the confusion in using the term mitigation plan (an enforcement mitigation plan vs. a vegetation mitigation plan). It also allows for different VRF and VSL from the other components of version 1 R1. R1.5 the imminent threat process in version 1 is replaced by R4 in version 2. It is an improvement over version 1 in that reporting is directed to the switching authority which has direct ability to take action.	1. An encroachment into the Minimum Vegetation Clearance Distance (MVCD) as shown in Table 2, observed in real time, absent a Sustained Outage, 2. An encroachment due to a fall-in from inside the active transmission line ROW that caused a vegetation-related Sustained Outage, 3. An encroachment due to blowing together of applicable lines and vegetation located inside the active transmission line ROW that caused a vegetation-related Sustained Outage, 4. An encroachment due to a grow-in that caused a vegetation-related Sustained Outage. **Rationale (R1 and R2)** The MVCD is a calculated minimum distance stated in feet (meters) to prevent spark-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method. **R3.** Each Transmission Owner shall document the procedures, processes, or specifications it uses to prevent the encroachment of vegetation into the MVCD. Such documentation will incorporate the dynamics of a transmission line conductor's movement throughout its Rating and Rated Electrical Operating Conditions and the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the Transmission Owner's applicable lines. **Rationale (R3)** Provide a basis for evaluation on the intent and competency of the Transmission Owner in maintaining vegetation. There may be many acceptable approaches to maintain clearances. However, the Transmission Owner should be able to state what its approach is and how it conducts work to maintain clearances. See Figure 1 for an illustration of possible conductor locations.

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2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap. **R1.2.2.1** Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied. **R1.2.2.2** Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied. **R1.3.** All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner, to perform their duties. **R1.4.** Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner is restricted from attaining the clearances specified in Requirement 1.2.1. **R1.5.** Each Transmission Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.		**R4.** Each Transmission Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated transmission line when qualified personnel confirm the existence of a vegetation condition that is likely to cause a Fault at any moment. **Rationale (R4)** To ensure expeditious communication between qualified field personnel and proper operating personnel when a critical situation is confirmed. Qualified field personnel may include lineworkers and utility arborists. **R5.** Each Transmission Owner shall take corrective action when it is constrained from performing planned vegetation work, where a transmission line is put at potential risk due to the constraint. **Rationale (R5)** Legal actions and other events may occur which result in constraints that prevent the Transmission Owner from performing planned vegetation maintenance work. In cases where the transmission line is put at potential risk due to constraints, the intent is for the Transmission Owner to put interim measures in place, rather than do nothing. For example, in the 2003 NE blackout a Transmission Owner was prevented by a court order from performing planned work. However, when the court order expired, the TO failed to take action to maintain the vegetation resulting in a sustained outage that contributed to the cascade. The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.
R2. The Transmission Owner shall create and implement an annual plan for vegetation management work to ensure	The Standard Drafting Team revised the language in the existing standard which reads in part, "The Transmission Owner shall create and implement an annual plan..." to	**R7.** Each Transmission Owner shall complete the work in an annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. Modifications to

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the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.	"Each Transmission Owner shall complete the work in an annual vegetation work plan…" setting an expectation that the work identified will be completed, as noted in the Rationale. In addition, the Team eliminated prescriptive language in R2 of the existing standard. The revised requirement is an improvement upon the current standard in that it clearly establishes the true intent of this requirement, completing the work in the plan and ensuring no vegetation encroaches into the MVCD.	the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk of a vegetation encroachment. Examples of reasons for modification to annual plan may include: • Change in expected growth rate/ environmental factors • Major storms • Rescheduling work between growing seasons • Crew or contractor availability/ Mutual assistance agreements • Identified unanticipated high priority work • Weather conditions/Accessibility • Permitting delays • Land ownership changes/Change in land use by the landowner • Funding adjustments (increase or decrease) • Emerging technologies **Rationale (R7)** This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. An annual vegetation work plan allows for work to be modified for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that the changes do not violate the encroachment within the MVCD.
R3. The Transmission Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission Owner to have been caused by vegetation. **R3.1.** Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24-	R3 Moved: In general, reporting requirement elements are moved to the Additional Compliance Information section of the standard. Reporting elements are, in themselves, documentation rudiments and do not add or subtract from electric system reliability. Format changes R3.1 Moved: Explanatory text moved to M1 and M2 Informational in nature. Format change. R3.2 Moved: The exclusions for reporting an outage were	**Additional Compliance Information** ***Periodic Data Submittal:*** The Transmission Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of transmission lines determined by the Transmission Owner to have been caused by vegetation that includes, as a minimum, the following: o The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a

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hour period. **R3.2.** The Transmission Owner is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation). **R3.3.** The outage information provided by the Transmission Owner to the RRO, or the RRO's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner. **R3.4.** An outage shall be categorized as one of the following: **R3.4.1.** Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW; **R3.4.2.** Category 2 — Fall-ins: Outages	placed in the Applicability Section – Other. The placement at the beginning of the Standard call attention to the overall impact to all requirements in the Standard R3.3 Moved: Outage information moved to Additional Compliance Information section. Informational in nature R3.4 Moved: Outage categories moved to Additional Compliance Information section. Informational in nature R3.4.1 Moved: Category 1 moved and expanded to differentiate between vegetation related sustained outages outside and within the ROW on IROL or Major WECC transfer path and non IROL lines or Major WECC transfer paths Category 1 outages were separated into 1A and 1B. R3.4.2 Moved: Category 2 reporting moved to Additional Compliance Information section. R3.4.3 Eliminated: Category 3 reporting for fall-in outside the right of way was eliminated. Vegetation fall-in's from outside the transmission right of way are not a standard violation and thus not a requirement. The reporting requirement is currently for informational purposes only. Added Category 4: Sustained outages from vegetation and conductors blowing together created a new Category 4 classification. Information located within the Additional Compliance Information section. No change in reliability.	description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the Transmission Owner. A Sustained Outage is to be categorized as one of the following: o Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable transmission lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the active transmission line ROW; o Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable transmission lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the active transmission line ROW; o Category 2 — Fall-ins: Sustained Outages caused by vegetation falling into applicable transmission lines from within the active transmission line ROW; o Category[3]4 — Blowing together: Sustained Outages caused by vegetation and applicable transmission lines blowing together from within the active transmission line ROW. The Regional Entity will report the outage information provided by Transmission Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages. 3 Category 3 reporting is eliminated.

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caused by vegetation falling into lines from inside the ROW; **R3.4.3.** Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.		
R4. The RRO shall report the outage information provided to it by Transmission Owner's, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the RRO as a result of any of the reported outages.	R4. Eliminated: RRO is now the Regional Entity. The Regional Entity is instructed per the periodic data submittal within the Additional Compliance Information section to report the outage information provided by Transmission Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages. No change in reliability.	

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Transmission Vegetation Management
Standard FAC-003-2 Technical Reference

Prepared by the

North American Electric Reliability Corporation

Vegetation Management Standard Drafting Team

June 28, 2010

Table of Contents

Introduction

This document is intended to provide supplemental information and guidance for complying with the requirements of Reliability Standard FAC-003-2.

The purpose of the Standard is to improve the reliability of the electric transmission system by preventing those vegetation related outages that could lead to Cascading.

Compliance with the Standard is mandatory and enforceable.

Special Note: The Application of Results-Based Approach to FAC-003-2

In its three-year assessment as the ERO, NERC acknowledged stakeholder comments and committed to:

i) addressing quality issues to ensure each reliability standard has a clear statement of purpose, and has outcome-focused requirements that are clear and measurable; and
ii) eliminating requirements that do not have an impact on bulk power system reliability.

In 2010, the Standards Committee approved a recommendation to use Project 2007-07 Vegetation Management as a first proof of concept for developing results-based standards.

The Standard Drafting Team (SDT) employed a defense-in-depth[1] strategy for FAC-003-2, where each requirement has a role in preventing those vegetation related outages that could lead to Cascading. This portfolio of requirements was designed to achieve an overall defense-in-depth strategy and to comply with the quality objectives identified in the *Acceptance Criteria of a Reliability Standard* document.

The SDT developed a portfolio of performance, risk, and competency-based mandatory reliability requirements to support an effective defense-in-depth strategy. Each Requirement was developed using one of the following requirement types:

a) Performance-based - defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?
b) Risk-based - preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?
c) Competency-based - defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

The drafting team reviewed and edited version 1 of FAC-003-1 to remove prescriptive and administrative language in order to distill the technical requirements down to their

[1] A defense-in-depth strategy for reliability standards recognizes that each requirement in the NERC standards has a role in preventing system failures, and that these roles are complementary and reinforcing. These prevention measures should be arranged in a series of defensive layers or walls. No single defensive layer provides complete protection from failure by itself. But taken together, with well-designed layers including performance, risk, and competency-based requirements, a defense-in-depth approach can be very effective in preventing future large scale power system failures.

essential reliability content. Text that is explanatory in nature is placed in a special section of the standard entitled Guideline and Technical Basis to aid in the understanding of the requirements. Furthermore, Rationale text boxes are inserted alongside each requirement to communicate the foundation for the requirement.

Disclaimer

This supporting document is supplemental to the reliability standard FAC-003-2 — Transmission Vegetation Management and does not contain mandatory requirements subject to compliance review.

Preface

The NERC Vegetation Management Standard Drafting Team (VM SDT) acknowledges those across the industry who contributed to the development of this Standard and companion Technical Reference document. The Technical Reference document is intended to provide supplemental explanatory background and guidance related to requirements contained in the Standard but does not in itself contain requirements subject to compliance review.

The VM SDT believes that a well designed and executed Transmission Vegetation Management Program (TVMP) will have few problems meeting the requirements of this Standard. While the Standard requires a TVMP to contain certain elements, it allows the Transmission Owner flexibility in designing a TVMP to meet local needs provided it also meets the purpose of the Standard.

While there are many approaches to vegetation management, the VMSDT supports industry best practices contained in ANSI A300 (Part 7) – Integrated Vegetation Management (IVM) practices on Utility Rights-of-way, as well as the companion publication Best Management Practices – Integrated Vegetation Management, as an effective strategy to maintain compliance with this Standard. ANSI A300 (Part 7), approved by industry consensus in 2006, contains many elements needed for an effective TVMP as required by this Standard. One key element is the “wire zone – border zone” concept. Supported by over 50 years of continuous research, wire zone – border zone is a proven method to manage vegetation on transmission rights-of-ways and is an industry accepted best practice to help ensure electric system reliability.

The VM SDT believes that Transmission Owners who adopt and effectively implement IVM principles, particularly the “wire zone – border zone” concept, are far less likely to experience a vegetation caused outage than those who do not.

Definition of Terms

Vegetation Inspection** — The systematic examination of vegetation conditions on an Active Transmission Line Right-of-Way which may be combined with a general line inspection.

The inspection includes the identification of any vegetation that may pose a threat to reliability prior to the next planned inspection or maintenance work, considering the current location of the conductor and other possible locations of the conductor due to sag and sway for rated conditions.

This definition allows both maintenance inspections and vegetation inspections to be performed concurrently.

*To be added to the NERC glossary of terms with final approval of this standard revision
** This is a modification to a defined term in the NERC glossary.

Applicability of the Standard

4. Applicability

4.1. Functional Entities:
Transmission Owners

4.2. Facilities: *Defined below, including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities:*

- ***4.2.1*** *Overhead transmission lines operated at 200kV or higher.*
- ***4.2.2*** *Overhead transmission lines operated below 200kV having been identified as included in the definition of an Interconnection Reliability Operating Limit (IROL) under NERC Standard FAC 014 by the Planning Coordinator.*
- ***4.2.3*** *Overhead transmission lines operated below 200 kV having been identified as included in the definition of one of the Major WECC Transfer Paths in the Bulk Electric System.*
- ***4.2.4*** *This Standard does not apply to Facilities identified above (4.2.1 through 4.2.3) located in the fenced area of a switchyard, station or substation.*

4.3. Enforcement: *The reliability obligations of the applicable entities and facilities are contained within the technical requirements of this standard.*

4.4. Other:
This Standard does not apply to any occurrence, non-occurrence, or other set of circumstances that are beyond the control of a Transmission Owner subject to this reliability standard, including acts of God, flood, drought, earthquake, major storms, fire, hurricane, tornado, landslides, ice storms, vehicle contact with tree, human activity involving: removal of, installation of, or digging around vegetation, animals severing trees, lightning, epidemic, strike, war, riot, civil disturbance, sabotage, vandalism, terrorism, wind shear, or fresh gale (or higher wind speed) that restricts or prevents performance to comply with this reliability standard's requirements. Nothing in this section should be construed to limit the Transmission Owner's right to exercise its full legal rights on the Active Transmission Line ROW.

In Order 693, FERC discussed the 200 kV bright-line test of applicability. While FERC did not change the 200 kV bright-line, the Commission remained concerned that there may be some transmission lines operating at lesser voltages that could have significant impact on the Bulk Electric System that should therefore be subject to this standard.

NERC Standard FAC-014 has the stated purpose, "*To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.*" FAC-014 requires Reliability Coordinators, Planning Coordinators, and Transmission Planners to have a methodology to identify all lines that might comprise an IROL. Thus, these entities would identify sub-200 kV lines that qualify as part of an IROL and should be subject to FAC-003-2.

[1] EPAct 2005 section 1211c: "*Access approvals by Federal agencies*".

Although all three entities may prepare the list of elements, FAC-003-2 presently does not specify that it is the list from the Planning Coordinator that should be used by Transmission Owners for FAC-003. However, the Time Horizon needed to plan vegetation management work does not lend itself to the operating horizon of a Reliability Coordinator. Additionally, the Planning Coordinator has a wider-area view than the Transmission Planner and could thus identify any elements of importance to a sub-set of its area that might be missed by a Transmission Planner.

Transmission Owners, who do not already get the list of circuits included in the definition of an IROL, can get them from the Planning Coordinator. Specifically R5 of FAC-014 specifies that "*The Reliability Coordinator, Planning Authority (Coordinator) and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits*"

Vegetation-related Sustained Outages that occur due to natural disasters are beyond the control of the Transmission Owner. These events are not classified as vegetation-related Sustained Outages and are therefore exempt from the Standard. Transmission lines are not designed to withstand the impacts of natural disasters such as flood, drought, earthquake, major storms, fire, hurricane, tornado, landslides, ice storms, etc. In the aftermath of catastrophic system damage from natural disasters the Transmission Owner's focus is on electric system restoration for public safety and critical support infrastructure.

Sustained Outages due to human or animal activity are beyond the control of the Transmission Owner. These outages are not classified as vegetation-related Sustained Outages and are therefore exempt from the Standard. Examples of these events may include new plantings by outside parties of tall vegetation under the transmission line planted since the last Vegetation Inspection, tree contacts with line initiated by vehicles, logging activities, etc.

The foregoing exemptions are addressed in a new subsection, 4.4 Other, of the Applicability section. Referred to collectively as force majeure events and activities, this section applies to all requirements in FAC-003-2.

The reliability objective of this NERC Vegetation Management Standard ("Standard") is to prevent vegetation-related outages which could lead to Cascading by effective vegetation maintenance while recognizing that certain outages such as those due to vandalism, human errors and acts of nature are not preventable. Operating experience clearly indicates that trees that have grown out of specification could contribute to a cascading grid failure, especially under heavy electrical loading conditions.

Serious outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. To properly reduce and manage this risk, it is necessary to apply the Standard to applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee. For the purposes of the Standard and this Technical Reference document, the term "public lands" includes municipal lands, village lands, city lands, and land owned by a host of other governmental entities.

The Standard addresses vegetation management along applicable overhead lines that serve to connect one electric station to another. However, it is not intended to be applied to lines sections inside the electric station fence or other boundary of an electric station, submarine or underground lines.

The Standard is intended to reduce the risk of Cascading involving vegetation. It is not intended to prevent customer outages from occurring due to tree contact with all transmission lines and voltages. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this Standard is not written to address such isolated situations which have little impact on the overall Bulk Electric System.

Vegetation growth is constant and always present. Unmanaged vegetation poses an increased outage risk when numerous transmission lines are operating at or near their Rating. This poses a significant risk of multiple line failures and Cascading. On the other hand, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are statistically intermittent. The probability of occurrence of these events is not dependent on heavy loads. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures.

In preparing the original vegetation management standard in 2005, industry stakeholders set the threshold for applicability of the standard at 200kV. This was because an unexpected loss of lines operating at above 200kV has a higher probability of initiating a widespread blackout or cascading outages compared with lines operating at less than 200kV.

The original NERC Standard FAC-003-1 also allowed for application of the standard to “critical” circuits (critical from the perspective of initiating widespread blackouts or cascading outages) operating below 200kV. While the percentage of these circuits is relatively low, it remains a fact that there are sub-200kV circuits whose loss could contribute to a widespread outage. Given the very limited exposure and unlikelihood of a major event related to these lower-voltage lines, it would be an imprudent use of resources to apply the Standard to all sub-200kV lines. The drafting team, after evaluating several alternatives, selected the IROL and WECC Major Transfer Path criteria to determine applicable lines below 200 kV that are subject to this standard.

Active Transmission Line ROW

The term “Active Transmission Line Right of Way” is defined in the Standard in a footnote repeated for convenience below:

> *A strip or corridor of land that is occupied by active transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities. However, it is not to be less than the width of the easement itself unless the easement exceeds distances as shown in Table 3 for various voltage classes.*

The term Right of Way (ROW) can be used in reference to many situations. This is partially because some lines are built on the land that is owned fee simple by the transmission owner, other lines are built across federal or provincial lands with only limited rights under a permit or agreement, and many other lines cross lands with only limited easement rights to construct, operate and maintain the line. Transmission line configurations on ROWs are present in many combinations of multiple circuits on various tower types. The number of circuits and configurations change along the length of the ROW due to circuits departing to other locations or terminating at nearby substations. Figures 1, 2 and 3 on the following pages depict several typical transmission line configurations on typical rights of way.

A Transmission Owner may plan for a nominal width along the entire length of a line during planning using its design specifications for a particular circuit configuration and voltage. The actual acquired ROW width at the time a circuit is constructed is however impacted in many cases, by other considerations. Those considerations include other future circuits that may be built adjacent to the subject line, or property parcels with unusual ‘extra” widths due to special property owner demands during initial acquisition, or other existing lines adjacent to the subject line (which may be retired or abandoned at a future date). Refer to Figures 1 and 3 for common examples of such situations.

This Standard requires the Transmission Owner to prevent sustained outages due to vegetation “growing into” or “blowing-together” with line conductors if that vegetation is under the line or growing beside the line (provided the Transmission Owner has the legal right to remove or trim the vegetation growing beside the line). Transmission Owners are also required to prevent sustained outages due to fall-ins from trees that, before falling, were standing inside the limits established in footnote 2 and associated “Table 3” (see below).

However it is recognized that any requirement in this standard to impose violations for sustained outages due to “fall-ins” must consider the impact of forcing the clearing of ROWs to the legal edge or to widths wider than they are typically managed. Therefore the standard drafting team inserted the subject footnote “active transmission line ROW” to provide a distance for a Transmission Owner to use if they do not already have a codified ROW width for a particular circuit or voltage”. This approach of defining “active” and “inactive” right of way is intended to clarify the confusion created by the current standard which simply states that a fall-in from within the ROW is a violation. This provides the Transmission Owner with a means to define a right of way width that is applicable to fall-ins, provided it is not less than those limits in “Table 3”.

69 - 138 kV	37.5 ft.
139 - 230 kV	50 ft.
231 - 345 kV	75 ft.
346 - 500 kV	87.5 ft.
501 - 765 kV	100 ft.

"Table 3 – Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW"

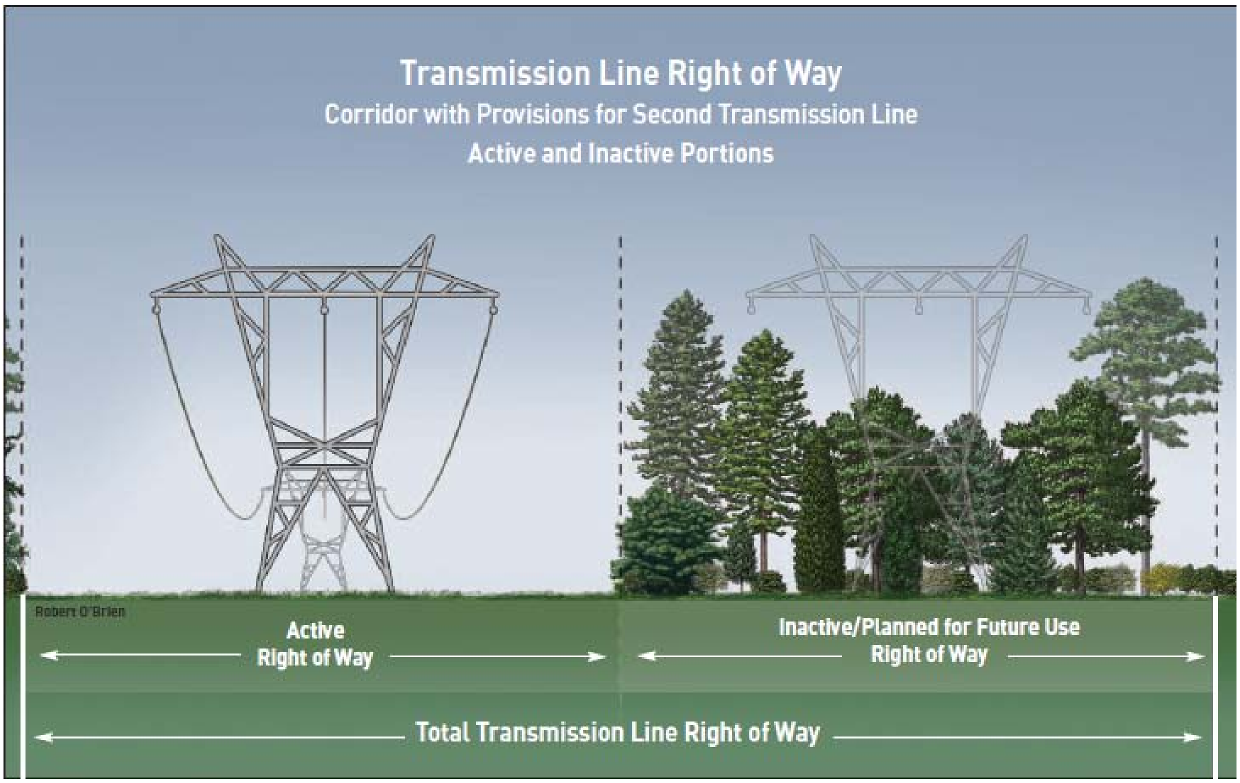


Figure 1

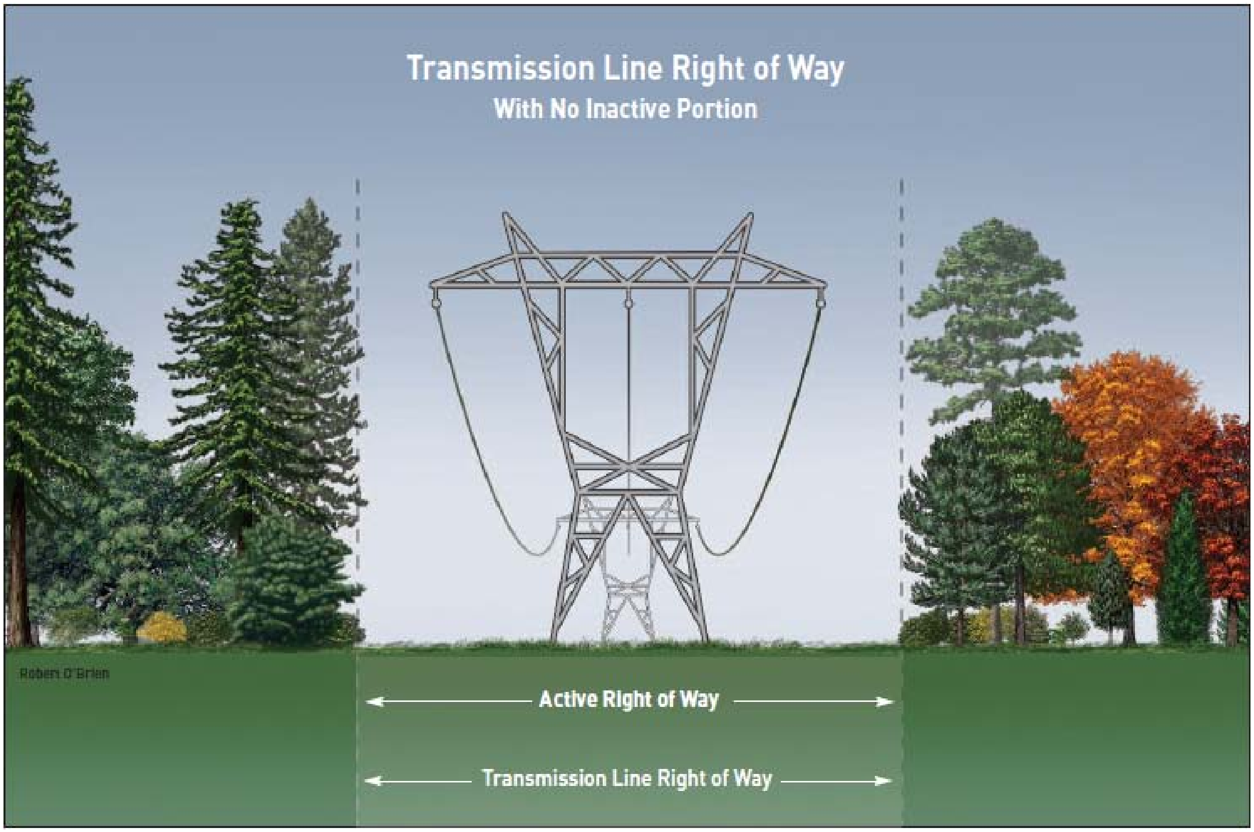

Transmission Line Right of Way
With No Inactive Portion
Robert O'Brien
Active Right of Way
Transmission Line Right of Way

Figure 2

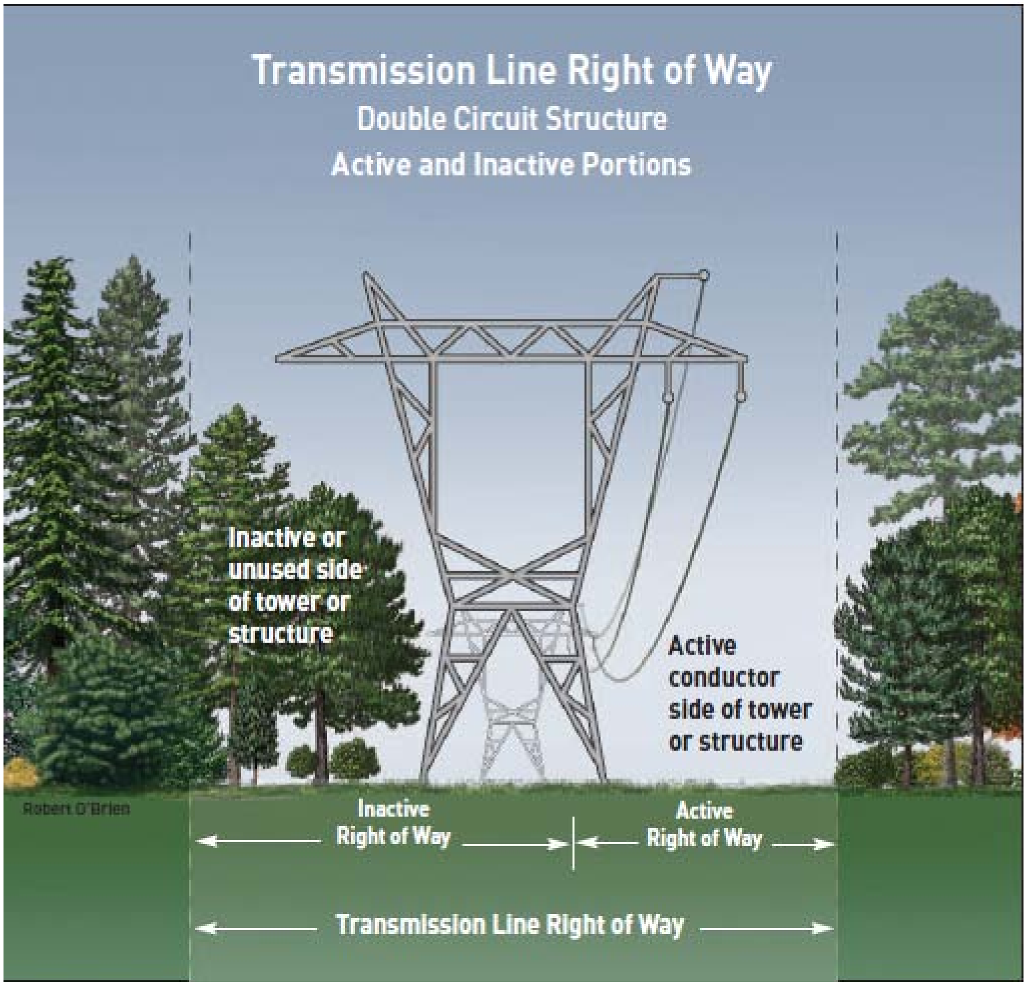

Transmission Line Right of Way
Double Circuit Structure
Active and Inactive Portions
Inactive or unused side of tower or structure
Active conductor side of tower or structure
Inactive Right of Way
Active Right of Way
Transmission Line Right of Way
Robert O'Brien

Figure 3

Requirements R1 and R2

> **Rationale**
> The MVCD is a calculated minimum distance stated in feet (meters) to prevent spark-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method.

R1. *Each Transmission Owner shall manage vegetation to prevent encroachment that could result in a Sustained Outage of any line identified as an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions). Types of encroachment include:*

1. *An encroachment into the Minimum Vegetation Clearance Distance (MVCD) as shown in Table 2, observed in real time, absent a Sustained Outage,*
2. *An encroachment due to a fall-in from inside the Active Transmission Line ROW that caused a vegetation-related Sustained Outage,*
3. *An encroachment due to blowing together of applicable lines and vegetation located inside the Active Transmission Line ROW that caused a vegetation-related Sustained Outage,*
4. *An encroachment due to a grow-in that caused a vegetation-related Sustained Outage.*

R2. *Each Transmission Owner shall manage vegetation to prevent encroachment that could result in a Sustained Outage of applicable lines that are <u>not</u> elements of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions). Types of encroachment include:*

1. *An encroachment into the Minimum Vegetation Clearance Distance (MVCD) as shown in Table 2, observed in real time, absent a Sustained Outage,*
2. *An encroachment due to a fall-in from inside the Active Transmission Line ROW that caused a vegetation-related Sustained Outage,*
3. *An encroachment due to blowing together of applicable lines and vegetation located inside the Active Transmission Line ROW that caused a vegetation-related Sustained Outage,*
4. *An encroachment due to a grow-in that caused a vegetation-related Sustained Outage.*

M1. *Each Transmission Owner has evidence that it managed vegetation as described in R1. Examples of acceptable forms of evidence may include attestations, reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-Time observations of any MVCD encroachments.*

Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. If an investigation of a Fault by a qualified person confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered a Real-time observation.

M2. *Each Transmission Owner has evidence that it managed vegetation as described in R2. Examples of acceptable forms of evidence may include attestations, reports containing no*

Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-Time observations of any MVCD encroachments.

Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. If an investigation of a Fault by a qualified person confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered a Real-time observation.

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the prevention of vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each Transmission Owner to prevent vegetation from encroaching within the Minimum Vegetation Clearance Distance of transmission lines. R1 is applicable to lines “identified as an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions) to avoid a Sustained Outage”. R2 applies to all other applicable lines that are not an element of an IROL or Major WECC Transfer Path.

The separation of applicability (between R1 and R2) recognizes that an encroachment into the MVCD of an IROL or Major WECC Transfer Path transmission line is a greater risk to the electric transmission system. Applicable lines that are not an element of an IROL or Major WECC Transfer Path are required to be clear of vegetation but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

These requirements (R1 and R2) state that if vegetation encroaches within the distances in Table 1 in Appendix 1 of this supplemental Transmission Vegetation Management Standard FAC-003-2 Technical Reference document, it is in violation of the standard. Table 1 tabulates the distances necessary to prevent spark-over based on the Gallet equations as described more fully in Appendix 1 below.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating (potentially in violation of other standards), the occurrence of a clearance encroachment may occur. For example, emergency actions taken by a Transmission Operator or Reliability Coordinator to protect an Interconnection may cause the transmission line to sag more and come closer to vegetation, potentially causing an outage. Such vegetation-related outages are not a violation of these requirements.

Evidence of violation of Requirement R1 and R2 include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the Active Transmission Line ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to blowing together of applicable lines and vegetation located inside the Active Transmission Line ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. If an investigation of a Fault by a qualified person confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered a Real-time observation.

With this approach, the VSLs were defined such that they directly correlate to the severity of a failure to keep vegetation away from conductors and to the corresponding performance level of the Transmission Owner’s vegetation program’s ability to meet the goal of “preventing a Sustained Outage that could lead to Cascading.” Thus violation severity increases with a Transmission Owner’s inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation, for example a limb that only partially breaks and intermittently contacts a conductor. Such events are considered to be a single vegetation-related Sustained Outage under the Standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will help prevent transmission outages.

Requirement R3

Rationale
Provide a basis for evaluation on the intent and competency of the Transmission Owner in maintaining vegetation. There may be many acceptable approaches to maintain clearances. However, the Transmission Owner should be able to state what its approach is and how it conducts work to maintain clearances. See Figure 1 *[in Standard FAC-003-2]* for an illustration of possible conductor locations.

R3. *Each Transmission Owner shall document the procedures, processes, or specifications it uses to prevent the encroachment of vegetation into the MVCD. Such documentation will incorporate the dynamics of a transmission line conductor's movement throughout its Rating and Rated Electrical Operating Conditions and the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the Transmission Owner's applicable lines.*

M3. *The procedures, processes, or specifications provided demonstrate that the Transmission Owner can prevent encroachment into the MVCD considering the factors identified in the requirement.*

Requirement R3 is a competency based requirement concerned with the procedures, processes, or specifications, a Transmission Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the Transmission Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the Transmission System. The approach provides the basis for evaluating the intent, allocation of appropriate resources and the competency of the Transmission Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the Transmission Owner must be able to state what its approach is and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach a Transmission Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the Transmission Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing as a reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 5 below.

Conductor Dynamics

In order for a Transmission Owner to develop a specific maintenance approach, it is important to understand the dynamics of a line conductor's movement. This paper will first address the complexities inherent in observing and predicting conductor movement, particularly for field personnel. It will then present some examples of maintenance approaches which Transmission Owners may consider that take into account these complexities, while resulting in practical approaches for field personnel.

Additionally, it is important the Transmission Owner consider all conductor locations, the MVCD, and vegetation growth between maintenance activities when developing a maintenance approach.

Understanding Conductor Position and Movement

The conductor's position in space at any point in time is continuously changing as a reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading.

As a consequence of these loading variables, the conductor's position in space is dynamic and moving. When calculating the range of conductor positions, the Transmission Owner should use the same design criteria and assumptions that the Transmission Owner uses when establishing Ratings and SOL, as described in other standards. Typically, the greatest conductor movement would be at mid-span. As the conductor moves through various positions, a spark-over zone surrounding the conductor moves with it. The radius of the spark-over zone may be found by referring to Table 1 ("Minimum Vegetation Clearance Distances") in the standard. For illustrations of this zone and conductor movements, Figures 4 through 6 below demonstrate these concepts. At the time of making a field observation, however, it is very difficult to precisely know where the conductor is in relation to its wide range of all possible positions. Therefore, Transmission Owners must adopt maintenance approaches that account for this dynamic situation.

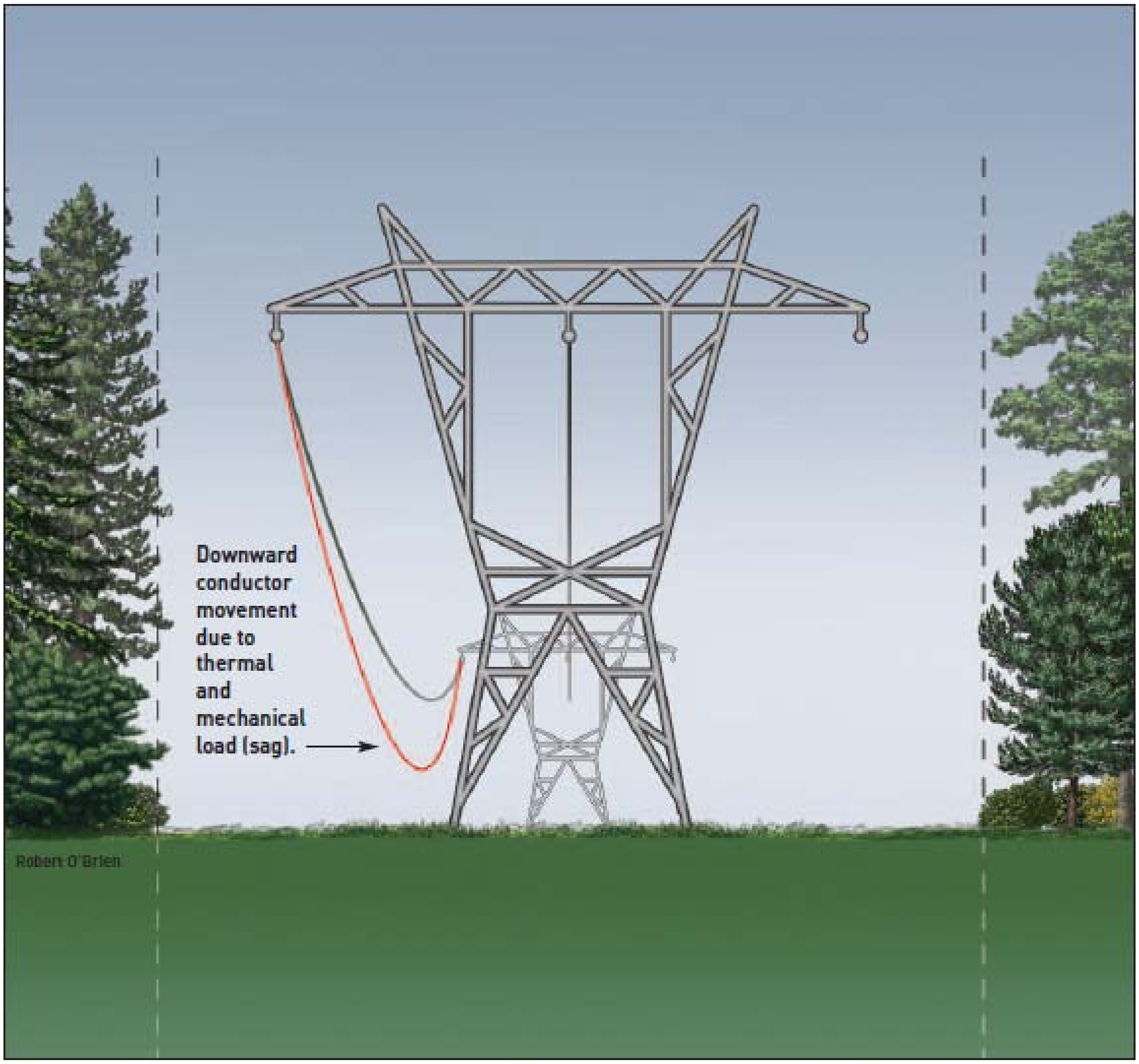

Downward
conductor
movement
due to
thermal
and
mechanical
load (sag).
Robert O'Brien

Figure 4

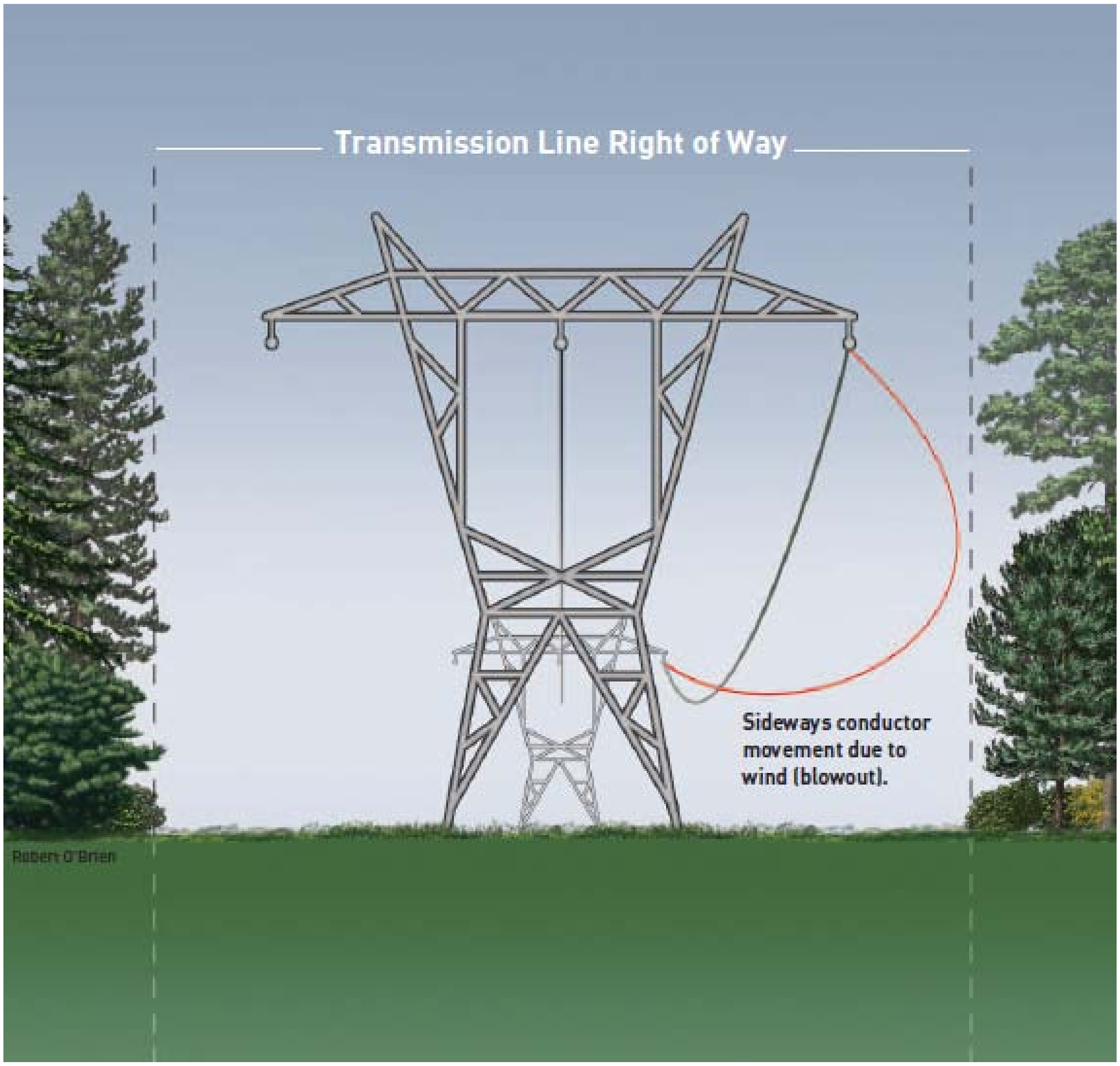
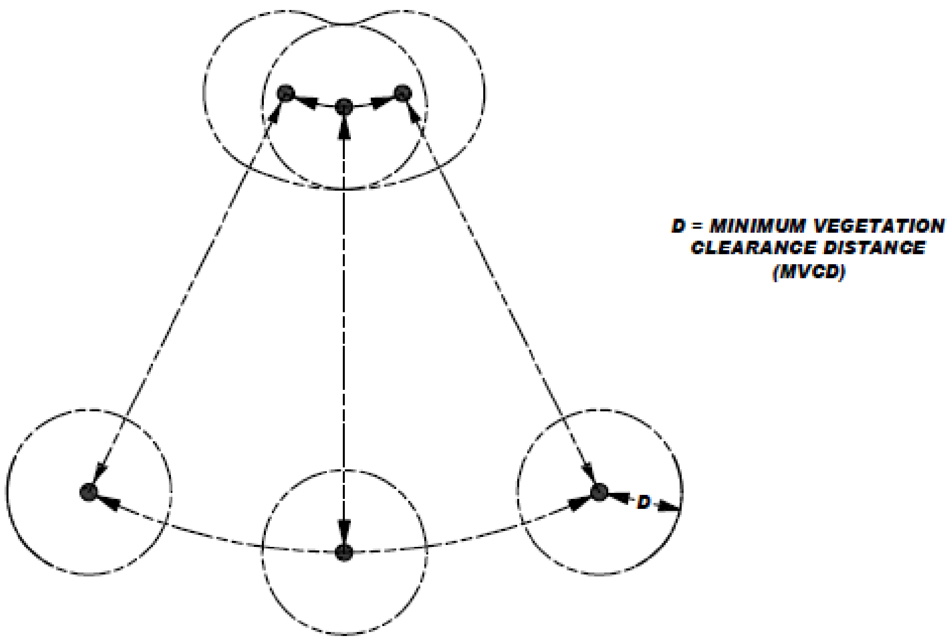

Transmission Line Right of Way
Sideways conductor movement due to wind (blowout).
Robert O'Brien

Figure 5



Cross-Section View of a Single Conductor

At a Given Point Along The Span

Showing Six Possible Conductor Positions Due to Movement

Resulting From Thermal and Mechanical Loading

For Consideration in Developing a Maintenance Approach

Figure 6

Selecting a Maintenance Approach

In order to maintain adequate separation between vegetation and transmission line conductors, the Transmission Owner must craft a maintenance strategy that keeps vegetation well away from the spark-over zone mentioned above. In fact, it is generally necessary to incorporate a variety of maintenance strategies. For example, one Transmission Owner may utilize a combination of routine cycles, traditional IVM techniques and long-term planning. Another Transmission Owner may place a higher reliance on frequent inspections and quick remediation as opposed to a cyclical approach. This variation of approaches is further warranted when factors, such as terrain, legal and other constraints, vegetation types, and climates, are considered in developing a Transmission Owner's specific approach to satisfying this requirement.

The following is a sample description of one combination of strategies which may be utilized by a Transmission Owner.
A Transmission Owner's basic maintenance approach could be to remove all incompatible vegetation from the right of way if it has the right to do so and has no constraints. In mountainous terrain, however, this strategy could change to one where the Transmission Owner manages vegetation based on vegetation-to-conductor clearances, since it might not be necessary to remove vegetation in a valley that is far below.

If faced with constraints and assuming a line design with sufficient ground clearance, the Transmission Owner 's approach could then be to allow vegetation such as fruit trees, but perhaps only up to a given height at maturity (perhaps 10 feet from the ground). If constraints cannot be overcome and if design clearances are sufficient, an exception to the Transmission Owner's 10-foot guideline might be made. Finally, if the Transmission Owner has chosen to utilize vegetation-to-conductor clearance distance methods, the Transmission Owner could have an inspection regimen in place to regularly ensure that any impending clearance problems are identified early for rectification.

ANSI A300 – Best Management Practices for Tree Care Operations

A description of ANSI A-300, part 7, is offered below to illustrate another maintenance approach that could be used in developing a comprehensive transmission vegetation management program.

Introduction

Integrated Vegetation Management (IVM) is a best management practice conveyed in the American National Standard for Tree Care Operations, Part 7 (ANSI 2006) and the International Society of Arboriculture *Best Management Practices: Integrated Vegetation Management* (Miller 2007). IVM is consistent with the requirements in FAC-003-02, and it provides practitioners with what industry experts consider to be appropriate techniques to apply to electric right-of-way projects in order to meet or exceed the Standard.

IVM is a system of managing plant communities whereby managers set objectives; identify compatible and incompatible vegetation; consider action thresholds; and evaluate, select and implement the most appropriate control method or methods to achieve set objectives. The choice of control method or methods should be based on the environmental impact and anticipated effectiveness; along with site characteristics, security, economics, current land use and other factors.

Planning and Implementation

Best management practices provide a systematic way of planning and implementing a vegetation management program. While designed primarily with transmission systems in mind, it is also applicable to distribution projects. As presented in ANSI A300 part 7 and the ISA best management practices, IVM consists of 6 elements:

1) Set Objectives
2) Evaluate the Site
3) Define Action Thresholds
4) Evaluate and Select Control Methods
5) Implement IVM
6) Monitor Treatment and Quality Assurance

The setting of objectives, defining action thresholds, and evaluating and selecting control methods all require decisions. The planning and implementation process is cyclical and continuous, because vegetation is dynamic and managers must have the flexibility to adjust their plans. Adjustments may be made at each stage as new information becomes available and circumstances evolve.

Set Objectives

Objectives should be clearly defined and documented. Examples of objectives can include promoting safety, preventing sustained outages caused by vegetation growing into electric facilities, maintaining regulatory compliance, protecting structures and security, restoring electric service during emergencies, maintaining access and clear lines of sight, protecting the environment, and facilitating cost effectiveness.

Objectives should be based on site factors, such as workload and vegetation type, in addition to human, equipment and financial resources. They will vary from utility to utility and project to project, depending on line voltage and criticality, as well as topographical, environmental, fiscal and political considerations. However, where it is appropriate, the overriding focus should be on environmentally-sound, cost effective control of species that potentially conflict with the electric facility, while promoting compatible, early successional, sustainable plant communities.

Work Load Evaluations

Work-load evaluations are inventories of vegetation that could have a bearing on management objectives. Work load assessments can capture a variety of vegetation characteristics, such as location, height, species, size and condition, hazard status, density and clearance from conductors. Assessments should be conducted considering voltage, conductor sag from ambient temperatures and loading, and the potential influence of wind on line sway.

Evaluate and Select Control Methods

Control methods are the process through which managers achieve objectives. The most suitable control method best achieves management objectives at a particular site. Many cases call for a combination of methods. Managers have a variety of controls from which to choose, including manual, mechanical, herbicide and tree growth regulators, biological, and cultural options.

Manual Control Methods

Manual methods employ workers with hand-carried tools, including chainsaws, handsaws, pruning shears and other devices to control incompatible vegetation. The advantage of manual techniques is that they are selective and can be used where others may not be. On the other hand, manual techniques can be inefficient and expensive compared to other methods.

Mechanical Control Methods
Mechanical controls are done with machines. They are efficient and cost effective, particularly for clearing dense vegetation during initial establishment, or reclaiming neglected or overgrown right of way. On the other hand, mechanical control methods can be non-selective and disturb sensitive sites.

Tree Growth Regulator and Herbicide Control Methods
Tree growth regulators and herbicides can be effective for vegetation management. Tree growth regulators (TGRs) are designed to reduce growth rates by interfering with natural plant processes. TGRs can be helpful where removals are prohibited or impractical by reducing the growth rates of some fast-growing species.

Herbicides control plants by interfering with specific botanical biochemical pathways. Herbicide use can control individual plants that are prone to re-sprout or sucker after removal. When trees that re-sprout or sucker are removed without herbicide treatment, dense thickets develop, impeding access, swelling workloads, increasing costs, blocking lines-of-site, and deteriorating wildlife habitat. Treating suckering plants allows early successional, compatible species to dominate the right-of-way and out-compete incompatible species, ultimately reducing work.

Cultural Control Methods
Cultural methods modify habitat to discourage incompatible vegetation and establish and manage desirable, early successional plant communities. Cultural methods take advantage of seed banks of native, compatible species lying dormant on site. In the long run, cultural control is the most desirable method where it is applicable.

A cultural control known as cover-type conversion provides a competitive advantage to short-growing, early successional plants, allowing them to thrive and eventually out-compete unwanted tree species for sunlight, essential elements and water. The early successional plant community is relatively stable, tree-resistant and reduces the amount of work, including herbicide application, with each successive treatment.

Wire-Border Zone
The wire-border zone technique is a management philosophy that can be applied through cultural control. W.C. Bramble and W.R. Byrnes developed it in the mid-1980s out of research begun in 1952 on a transmission right-of-way in the Pennsylvania State Game Lands 33 Research and Demonstration project (Yahner and Hutnik (2004).

The wire zone is the section of a utility transmission right-of-way directly under the wires and extending outward about 10 feet on each side. The wire zone is managed to promote a low-growing plant community dominated by grasses, herbs and small shrubs (under 3 feet in height at maturity). The border zone is the remainder of the right-of-way. It is managed to establish small trees and tall shrubs (under 25 feet in height at maturity). When properly managed, diverse, tree-resistant plant communities develop in wire and border zones. The communities not only protect the electric facility and reduce long-term maintenance, but also enhance wildlife habitat, forest ecology and aesthetic values.

Although the wire-border zone is a best practice in many instances, it is not necessarily universally suitable. For example, standard wire-border zone prescriptions may be unnecessary where lines are high off the ground, such as across low valleys or canyons, so the technique can be modified without sacrificing reliability.

One way to accommodate variances in topography is to establish different regions based on wire height. For example, over canyon bottoms or other areas where conductors are 100 feet or more above the ground, only a few trees are likely to be tall enough to conflict with the lines. In those cases, trees that potentially interfere with the transmission lines can be removed selectively on a case-by-case basis.

In areas where the wire is lower, perhaps between 50-100 feet from the ground, a border zone community can be developed throughout the right-of-way. Note that in many cases, conductor attachment points are more than 50 feet off the ground, so a border zone community can be cultivated near structures. Where the line is less than 50 feet off the ground, managers could apply a full wire-border zone prescription.

An environmental advantage of this type of modification is stream protection. Streams often course through the valleys and canyons where lines are likely to be elevated. Leaving timber or border zone communities in canyon bottoms helps shelter this valuable habitat, enabling managers to achieve environmentally sensitive objectives.

Implement IVM

All laws and regulations governing IVM practices and specifications written by qualified vegetation managers must be followed. Integrated vegetation management control methods should be implemented on regular work schedules, which are based on established objectives and completed assessments. Work should progress systematically, using control measures determined to be best for varying conditions at specific locations along a right-of-way. Some considerations used in developing schedules include the importance and type of line, vegetation clearances, work loads, growth rate of predominant vegetation, geography, accessibility, and in some cases, time lapsed since the last scheduled work.

Clearances Following Work

Clearances following work should be sufficient to meet management objectives, including preventing trees from entering the Minimum Vegetation Clearance Distance, electric safety risks, service-reliability threats and cost.

Monitor Treatment and Quality Assurance

An effective program includes documented processes to evaluate results. Evaluations can involve quality assurance while work is underway and after it is completed. Monitoring for quality assurance should begin early to correct any possible miscommunication or misunderstanding on the part of crewmembers. Early and consistent observation and evaluation also provides an opportunity to modify the plan, if need be, in time for a successful outcome.

Utility vegetation management programs should have systems and procedures in place for documenting and verifying that vegetation management work was completed to specifications. Post-control reviews can be comprehensive or based on a statistically representative sample. This final review points back to the first step and the planning process begins again.

Summary of A-300 example

Integrated Vegetation Management offers among others, a systematic way of planning and implementing a vegetation management program as presented in ANSI A300 Part 7. This methodology enables a program to comply with the NERC *Transmission Vegetation Management Program* standard (FAC-003-2). Managers should select control options to best promote management objectives.

Vegetation Inspections

As with the ANSI A-300 example, The Transmission Owner's transmission vegetation management program (TVMP) establishes the frequency of vegetation inspections based upon many factors. Such local and environmental factors may include anticipated growth rates of the local vegetation, length of the growing season for the geographical area, limited Active Transmission Rights of Way width, rainfall amounts, etc.

Annual Work Plan

Requirement R7 of the Standard addresses the execution of the annual work plan. A comprehensive approach that exercises the full extent of legal rights is superior to incremental management in the long term because it reduces overall encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient at all locations on the Active Transmission Line Right of Way. Removal is superior to pruning. Removal minimizes the possibility of conflicts between energized conductors and vegetation. Since this is not always possible, the Transmission Owner's approach should be to use its prescribed vegetation maintenance methods to work towards or achieve the maximum use of the Active Transmission Line Right of Way.

Requirement R4

R4. *Each Transmission Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated transmission line when qualified personnel confirm the existence of a vegetation condition that is likely to cause a Fault at any moment.*

> **Rationale**
> To ensure expeditious communication between qualified field personnel and proper operating personnel when a critical situation is confirmed. Qualified field personnel may include lineworkers and utility arborists.

M4. *Each Transmission Owner that has a vegetation condition likely to cause a Fault at any moment, as confirmed by qualified personnel, will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders.*

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the Transmission Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of a qualified employee who personally identifies such a threat in the field. Confirmation could also be made by sending out a qualified person to evaluate a situation reported by a landowner or an unqualified employee.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The Transmission Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or positioning the system in recognition of the increasing risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some Transmission Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5

R5. *Each Transmission Owner shall take corrective action when it is constrained from performing planned vegetation work, where a transmission line is put at potential risk due to the constraint.*

M5. *Each Transmission Owner has evidence of the corrective action taken for each constraint where a transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, and evidence that a line was de-energized.*

Rationale

Legal actions and other events may occur which result in constraints that prevent the Transmission Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the Transmission Owner to put interim measures in place, rather than do nothing.

For example, in the 2003 NE blackout a Transmission Owner was prevented by a court order from performing planned work. However, when the court order expired, the TO failed to take action to maintain the vegetation resulting in a sustained outage that contributed to the cascade.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the Transmission Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the Transmission Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the Transmission Owner’s rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the Transmission Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the Transmission Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the Transmission Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for each location.
- In developing the specific action to mitigate the potential risk to the transmission line the Transmission Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The Transmission Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6

R6. *Each Transmission Owner shall perform a Vegetation Inspection of all applicable transmission lines at least once per calendar year.*

M6. *Each Transmission Owner has evidence that it conducted Vegetation Inspections at least once per calendar year for applicable transmission lines. Examples of acceptable forms of evidence may include work orders, invoices, or inspection records.*

Rationale
Inspections are used by Transmission Owners to prevent the encroachment of vegetation into the MVCD and provide a basis for assessing risk. This requirement sets a minimum vegetation inspection frequency of once per calendar year. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections that fits general industry practice. In addition, the fact that Vegetation Inspections can be performed in conjunction with general line inspections further facilitates a Transmission Owner's ability to meet this requirement. However, the Transmission Owner may determine that more frequent inspections are needed to maintain reliability levels, dependent upon such factors as anticipated growth rates of the local vegetation, length of the growing season for the geographical area, limited Active Transmission ROW width, and rainfall amounts. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSL for Requirement R6 has VSL categories ranked by the percentage of the required ROW inspections completed. To calculate the percentage of inspection completion, the Transmission Owner may choose units such as: line miles or kilometers, circuit miles or kilometers, pole line miles, ROW miles, etc.

For example, when a Transmission Owner operates 2,000 miles of 230 kV transmission lines this Transmission Owner will be responsible for inspecting all 2,000 miles of 230 kV transmission lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

Requirement R7

R7. *Each Transmission Owner shall complete the work in an annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk of a vegetation encroachment. Examples of reasons for modification to annual plan may include:*

> **Rationale**
> This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. An annual vegetation work plan allows for work to be modified for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that the changes do not violate the encroachment within the MVCD.

- *Change in expected growth rate/environmental factors*
- *Major storms*
- *Rescheduling work between growing seasons*
- *Crew or contractor availability/ Mutual assistance agreements*
- *Identified unanticipated high priority work*
- *Weather conditions/Accessibility*
- *Permitting delays*
- *Land ownership changes/Change in land use by the landowner*
- *Funding adjustments (increase or decrease)*
- *Emerging technologies*

M7. *Each Transmission Owner has evidence that it completed its annual vegetation work plan. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (including modifications if any), dated work orders, dated invoices, or dated inspection records.*

R7 is a risk-based requirement. The Transmission Owner is required to implement an annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a “span-by-span”, or even a “line-by-line” detailed description of all work to be performed. It is only intended to require that the Transmission Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

The ability to modify the work plan allows the Transmission Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the Transmission Owner’s system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan. Modifications to the annual work plan must always ensure the reliability of the electric Transmission system.

In general, the vegetation management maintenance approach should use the full extent of the Transmission Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the Active Transmission Line ROW is superior to incremental management in the long term because it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the Transmission Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Transmission Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the Transmission Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

Appendix 1: Clearance Distance Derivation by the Gallet Equation

The Gallet Equation is a well-known method of computing the required strike distance for proper insulation coordination, and has the ability to take into account various air gap geometries, as well as non-standard atmospheric conditions. When the Gallet Equation and conservative probabilistic methods are combined, i.e. deterministic design, sparkover probabilities of 10^{-6} or less are achieved. This approach is well known for its conservatism and was used to design the first 500 kV and 765 kV lines in North America [1]. Thus, the deterministic design approach using the Gallet Equation is used for the standard to compute the minimum strike distance between transmission lines and the vegetation that may be present in or along the transmission corridor.

Method Explanation (Gallet Equation)

In 1975 G. Gallet published a benchmark paper that provided a method to compute the critical flashover voltage (CFO) of various air gap geometries [4]. The Gallet Equation uses various “gap factors” to take into account various air gap geometries. Various gap factor values are provided in [1]. If the vegetation in a transmission corridor, e.g. a tree, is assumed electrically to be a large structure then the CFO of such an air gap geometry can be computed for dry or wet conditions using a well established equation proposed by Gallet [1],[2],[4],

$$CFO_A = k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} \tag{1}$$

where,

k_w	is defined as the factor that takes into account wet or dry conditions (dry = 1.0 and wet = 0.96) and phase arrangement (multiply by 1.08 for outside phase), e.g. outside phase and wet conditions = (0.96)(1.08) = 1.037,
k_g	is defined as the gap factor (1.3 for conductor to large structure),
D	is the strike distance (m),
CFO_A	is the CFO for the relative air density (kV).
δ	is defined as the relative air density and is approximately equal to (2) where *A* is the altitude in km,

$$\delta = e^{-\frac{A}{8.6}} \tag{2}$$

$$m = 1.25G_0\left(G_0 - 0.2\right) \tag{3}$$

$$G_0 = \frac{CFO_s}{500 \cdot D} \tag{4}$$

$$CFO_s = k_w \cdot k_g \cdot \frac{3400}{1+\frac{8}{D}} \tag{5}$$

where CFO_S is the CFO for standard atmospheric conditions (kV). Using (1)-(5), the required CFO_A can be computed using an iterative process.

Once the CFO_A is known, deterministic methods can be used to determine the required clearance distance. If we let the maximum switching overvoltage be equal to the withstand voltage of the air gap (CFO_A - 3σ) then the CFO_A can be written as (6).

$$CFO_A = \frac{V_m}{1-3\left(\frac{\sigma}{CFO_A}\right)} \tag{6}$$

where

V_m is equal to the maximum switching overvoltage, i.e. the value that has a 0.135% chance of being exceeded,

σ is the standard deviation of the air gap insulation,

CFO_A is the critical flashover voltage of the air gap insulation under non-standard atmospheric conditions.

The ratio of σ to the CFO_A given in (6) can be assumed to be 0.05 (5%) [1]. Thus, (6) can be written as (7).

$$CFO_A = \frac{V_m}{0.85} \tag{7}$$

Substituting (7) into (1) we arrive at (8).

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} \tag{8}$$

Equation 8 relates the maximum transient overvoltage, V_m, to the air gap distance, D. Using (8) to compute the required clearance distance for the specified air gap geometry (conductor to large structure) results in a probability of flashover in the range of 10^{-6}.

Transient Overvoltage

In general, the worst case transient overvoltages occurring on a transmission line are caused by energizing or re-energizing the line with the latter being the extreme case if trapped charge is present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to sparkover from the line conductor to nearby vegetation. Thus, the worst case scenarios that are typically analyzed for insulation coordination purposes (e.g. line energization and re-energization) can be ignored. For the purposes of FAC-003-2, the worst case transient overvoltage then becomes the maximum value that can occur with the line energized. Determining a realistic value of transient overvoltage for this situation is difficult because the maximum transient overvoltage factors listed in the literature are based on a

switching operation of the line in question. In other words, these maximum overvoltage values (e.g. the values listed in [2], [3] and [5]) are based on the assumption that the subject line is being energized, re-energized or de-energized. These operations, by their very nature, will create the largest transient overvoltages. Typical values of transient overvoltages of in-service lines, as such, are not readily available in the literature because the resulting level of overvoltage is negligible compared with the maximum (e.g. re-energizing a transmission line with trapped charge). A conservative value for the maximum transient overvoltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 p.u.[2]. This value is a conservative estimate of the transient overvoltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without a pre-insertion device (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. 362 kV), the maximum transient overvoltage of an "in-service" ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 p.u. or less [2]. It is well known that these theoretical transient overvoltages will not be experienced at locations remote from the bus at which they were created; however, in order to be conservative, it will be assumed that all nearby ac lines are subjected to this same level of overvoltage. Thus, a maximum transient overvoltage factor of 2.0 p.u. for 242 kV and below and 1.4 p.u. for ac transmission lines 362 kV and above is used to compute the required clearance distances for vegetation management purposes.

The overvoltage characteristics of dc transmission lines vary somewhat from their ac counterparts. The referenced empirically derived transient overvoltage factor used to calculate the minimum clearance distances from dc transmission lines to vegetation for the purpose of FAC-003-2 will be 1.8 p.u.[3].

Example Calculation

An example calculation is presented below using the proposed method of computing the vegetation clearance distances. It is assumed that the line in question has a maximum operating voltage of 550 kV_{rms} line-to-line. Using a per unit transient overvoltage factor of 1.4, the result is a peak transient voltage of 629 kV_{crest}. It is further assumed that the line in question operates at a maximum altitude of 7000 feet (2.134 km) above sea level.

The required withstand voltage of the air gap must be equal to or greater than 629 kV_{crest}. Since the altitude is above sea level, (1) - (5) have to be iterated on to achieve the desired result. Equation (9) can be used as an initial guess for the clearance distance.

$$D_i = \frac{8}{\frac{3400 \cdot k_w \cdot k_g}{\left(\frac{V_m}{0.85}\right)} - 1} \qquad (9)$$

For our case here, V_m is equal to 629 kV, k_w = 1.037 and k_g = 1.3. Thus,

$$D_i = \frac{8}{\frac{3400 \cdot k_w \cdot k_g}{\left(\frac{V_m}{0.85}\right)} - 1} = \frac{8}{\frac{3400 \cdot 1.037 \cdot 1.3}{\left(\frac{629}{0.85}\right)} - 1} = 1.535m \qquad (10)$$

Using (2)-(5) and (8) the withstand voltage of the air gap is next computed. This value will then be compared to the maximum transient overvoltage.

$$CFO_S = k_w \cdot k_g \cdot \frac{3400}{1+\frac{8}{D}} = 1.037 \cdot 1.3 \cdot \frac{3400}{1+\frac{8}{1.535}} = 737.7kV \tag{11}$$

$$\delta = e^{-\frac{A}{8.6}} = e^{-\frac{2.134}{8.6}} = 0.78 \tag{12}$$

$$G_O = \frac{CFO_S}{500 \cdot D} = \frac{737.7}{(500)\cdot(1.535)} = 0.961 \tag{13}$$

$$m = 1.25 \cdot G_O (G_O - 0.2) = 1.25 \cdot 0.961(0.961 - 0.2) = 0.915 \tag{14}$$

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} = (0.85)(1.037)(1.3)(0.78)^{0.915}\left(\frac{3400}{1+\frac{8}{1.535}}\right) = 499.8kV \tag{15}$$

The calculated V_m is less than 629 kV; thus, the clearance distance must be increased. A few iterations using (2)-(5) and (8) are required until the computed $V_m \geq 629$ kV. For this case it was found that D = 1.978 m (6.49 feet) yielded V_m = 629.3 kV. Using this clearance distance the following values were computed for the final iteration.

$$CFO_S = k_w \cdot k_g \cdot \frac{3400}{1+\frac{8}{D}} = 1.037 \cdot 1.3 \cdot \frac{3400}{1+\frac{8}{1.978}} = 908.5kV \tag{16}$$

$$\delta = e^{-\frac{A}{8.6}} = e^{-\frac{2.134}{8.6}} = 0.78 \tag{17}$$

$$G_O = \frac{CFO_S}{500 \cdot D} = \frac{908.5}{(500)\cdot(1.978)} = 0.919 \tag{18}$$

$$m = 1.25 \cdot G_O (G_O - 0.2) = 1.25 \cdot 0.919(0.919 - 0.2) = 0.825 \tag{19}$$

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} = (0.85)(1.037)(1.3)(0.78)^{0.825}\left(\frac{3400}{1+\frac{8}{1.978}}\right) = 629.3kV \tag{20}$$

Therefore, the minimum vegetation clearance distance for a maximum line to line ac operating voltage of 550 kV at 7000 feet above sea level is 1.978 m (6.49 feet). Table 1 provides calculated distances for various altitudes and maximum system operating ac voltages.

TABLE 1 — Minimum Vegetation Clearance Distances (MVCD)[3]
For **Alternating Current** Voltages

(AC) Nominal System Voltage (kV)	(AC) Maximum System Voltage (kV)	MVCD feet (meters) sea level	MVCD feet (meters) 3,000ft (914.4m)	MVCD feet (meters) 4,000ft (1219.2m)	MVCD feet (meters) 5,000ft (1524m)	MVCD feet (meters) 6,000ft (1828.8m)	MVCD feet (meters) 7,000ft (2133.6m)	MVCD feet (meters) 8,000ft (2438.4m)	MVCD feet (meters) 9,000ft (2743.2m)	MVCD feet (meters) 10,000ft (3048m)	MVCD feet (meters) 11,000ft (3352.8m)
765	800	8.06ft (2.46m)	8.89ft (2.71m)	9.17ft (2.80m)	9.45ft (2.88m)	9.73ft (2.97m)	10.01ft (3.05m)	10.29ft (3.14m)	10.57ft (3.22m)	10.85ft (3.31m)	11.13ft (3.39m)
500	550	5.06ft (1.54m)	5.66ft (1.73m)	5.86ft (1.79m)	6.07ft (1.85m)	6.28ft (1.91m)	6.49ft (1.98m)	6.7ft (2.04m)	6.92ft (2.11m)	7.13ft (2.17m)	7.35ft (2.24m)
345	362	3.12ft (0.95m)	3.53ft (1.08m)	3.67ft (1.12m)	3.82ft (1.16m)	3.97ft (1.21m)	4.12ft (1.26m)	4.27ft (1.30m)	4.43ft (1.35m)	4.58ft (1.40m)	4.74ft (1.44m)
230	242	2.97ft (0.91m)	3.36ft (1.02m)	3.49ft (1.06m)	3.63ft (1.11m)	3.78ft (1.15m)	3.92ft (1.19m)	4.07ft (1.24m)	4.22ft (1.29m)	4.37ft (1.33m)	4.53ft (1.38m)
161*	169	2ft (0.61m)	2.28ft (0.69m)	2.38ft (0.73m)	2.48ft (0.76m)	2.58ft (0.79m)	2.69ft (0.82m)	2.8ft (0.85m)	2.91ft (0.89m)	3.03ft (0.92m)	3.14ft (0.96m)
138*	145	1.7ft (0.52m)	1.94ft (0.59m)	2.03ft (0.62m)	2.12ft (0.65m)	2.21ft (0.67m)	2.3ft (0.70m)	2.4ft (0.73m)	2.49ft (0.76m)	2.59ft (0.79m)	2.7ft (0.82m)
115*	121	1.41ft (0.43m)	1.61ft (0.49m)	1.68ft (0.51m)	1.75ft (0.53m)	1.83ft (0.56m)	1.91ft (0.58m)	1.99ft (0.61m)	2.07ft (0.63m)	2.16ft (0.66m)	2.25ft (0.69m)
88*	100	1.15ft (0.35m)	1.32ft (0.40m)	1.38ft (0.42m)	1.44ft (0.44m)	1.5ft (0.46m)	1.57ft (0.48m)	1.64ft (0.50m)	1.71ft (0.52m)	1.78ft (0.54m)	1.86ft (0.57m)
69*	72	0.82ft (0.25m)	0.94ft (0.29m)	0.99ft (0.30m)	1.03ft (0.31m)	1.08ft (0.33m)	1.13ft (0.34m)	1.18ft (0.36m)	1.23ft (0.37m)	1.28ft (0.39m)	1.34ft (0.41m)

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above).

[3] The distances in this Table are the minimums required to prevent Flashover; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

TABLE 1 (CONT.) — Minimum Vegetation Clearance Distances (MVCD)
For **Direct Current** Voltages

(DC) Nominal Pole to Ground Voltage (kV)	**MVCD feet (meters) sea level**	**MVCD feet (meters) 3,000ft (914.4m) Alt.**	**MVCD feet (meters) 4,000ft (1219.2m) Alt.**	**MVCD feet (meters) 5,000ft (1524m) Alt.**	**MVCD feet (meters) 6,000ft (1828.8m) Alt.**	**MVCD feet (meters) 7,000ft (2133.6m) Alt.**	**MVCD feet (meters) (8,000ft (2438.4m) Alt.**	**MVCD feet (meters) 9,000ft (2743.2m) Alt.**	**MVCD feet (meters) 10,000ft (3048m) Alt.**	**MVCD feet (meters) 11,000ft (3352.8m) Alt.**
±750	13.92ft (4.24m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.9ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.07ft (3.07m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	(13.54ft 4.13m)
±500	7.89ft (2.40m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	4.78ft (1.46m)	5.35ft (1.63m)	5.55ft (1.69m)	5.75ft (1.75m)	5.95ft (1.81m)	6.15ft (1.87m)	6.36ft (1.94m)	6.57ft (2.00m)	6.77ft (2.06m)	6.98ft (2.13m)
±250	3.43ft (1.05m)	4.02ft (1.23m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5ft (1.52m)	5.17ft (1.58m)

List of Acronyms and Abbreviations

ANSI	American National Standards Institute
IEEE	Institute of Electrical and Electronics Engineers
IVM	Integrated Vegetation Management
NERC	North American Electric Reliability Corporation

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NERC
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Standards Announcement

Initial Ballot Window Open
July 9–19, 2010

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Project 2007-07: Transmission Vegetation Management

An initial ballot window for proposed standard FAC-003-2 — Transmission Vegetation Management is now open **until 8 p.m. Eastern on July 19, 2010**. An associated implementation plan has been posted with the revised standard.

Members of the ballot pool associated with this project will receive a separate e-mail with a link to the non-binding on the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs).

On March 18, 2010, FERC issued several orders and notices of proposed rulemakings pertaining to standards development activities and processes, suggesting a lack of progress in responding to directives from Order 693 as well in the timeliness of standards development in general. At the May 2010 NERC Board meeting, Gerry Cauley, NERC's President, also expressed these concerns, indicating that the resolution to these concerns is one of NERC's top priorities in the near term. As a result, the Standards Committee has authorized deviations from the normal standards development process for the Vegetation Management project, as well as other projects that have been through significant stakeholder review through the development process, to demonstrate that the NERC enterprise is responsive to FERC directives, and is making progress in developing new standards.

The Standards Committee approved the following deviations from the standards development process:

- The proposed changes to the standards will be posted for a shortened comment period;
- The ballot pool will be formed during the first few weeks of the comment period;
- The initial ballot will be conducted during the last 10 days of the comment period; and
- The drafting team may make modifications between the initial and recirculation ballots based on stakeholder comments to improve the overall quality of the standard.

Instructions

Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Next Steps

Voting results will be posted and announced after the ballot window closes.

Project Background

The project is an update to FAC-003-1, which was approved in 2006. The items identified for revision include the incorporation of FERC Order 693 comments related to applicability, procedural repairs to conform to the current standards format and development procedure, technical updates and guidance to address stakeholder suggestions, and the elimination of "fill-in-the-blank" components.

Project page: http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

Special notes about this project:
The NERC Standards Committee endorsed the use of Project 2007-07: Vegetation Management as the prototype for the proof-of-concept for using the "results-based" criteria for developing a reliability standard. The overall approach includes considerably more emphasis on the "concepts and assumptions" underlying the development of requirements and goes beyond the steps most drafting teams use when developing a standard. Accordingly, the "look and feel" of the vegetation management standard is quite different than NERC's existing standards. However, at the core is a set of mandatory and enforceable requirements with useful guidance supporting these requirements, an approach NERC's legal counsel has reviewed and finds acceptable. More information about results-based standards can be found at:
http://www.nerc.com/filez/standards/Project2010-06_Results-based_Reliability_Standards.html

Applicability of Standards in Project

Transmission Owners
Specific facilities (see standard)

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Lauren Koller at Lauren.Koller@nerc.net

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Standards Announcement

Ballot Pool and Pre-ballot Window (with Comment Period)
Project 2007-07: Vegetation Management

Now available at: http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

Project 2007-07: Vegetation Management

On March 18, 2010, FERC issued several orders and notices of proposed rulemakings pertaining to standards development activities and processes, suggesting a lack of progress in responding to directives from Order 693 as well in the timeliness of standards development in general. At the May 2010 NERC Board meeting, Gerry Cauley, NERC's President, also expressed these concerns, indicating that the resolution to these concerns is one of NERC's top priorities in the near term. As a result, the Standards Committee has authorized deviations from the normal standards development process for the Vegetation Management project, as well as other projects that have been through significant stakeholder review through the development process, to demonstrate that the NERC enterprise is responsive to FERC directives, and is making progress in developing new standards.

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Ballot Pool (through July 7, 2010)

Registered Ballot Body members may join the ballot pool **until 8 a.m. Eastern on July 7, 2010** to be eligible to vote in the upcoming ballot at the following page: https://standards.nerc.net/BallotPool.aspx. Members who join the ballot pool to vote on the standard will automatically be entered in a separate pool to participate in the non-binding poll of the associated violation risk factors (VRFs) and violation severity levels (VSLs). (As a reminder, this new approach for VRFs and VSLs is one of the updates reflected in the recently FERC-approved Reliability Standards Development Procedure – Version 7.)

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2007-07_FAC-003-2_in@nerc.com

Comment Period (through July 17, 2010)

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at 609-524-7047.

The documents for this project — including an off-line, unofficial copy of the questions listed in the comment form — are posted at the following site:
http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

Project Background

The project is an update to FAC-003-1, which was approved in 2006. The items identified for revision include the incorporation of FERC Order 693 comments related to applicability, procedural repairs to conform to the current standards format and development procedure, technical updates and guidance to address stakeholder suggestions, and the elimination of "fill-in-the-blank" components. More information is available on the project page:
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Ballot Results	
Ballot Name:	Project 2007-07 Vegetation Management FAC-003-2_in
Ballot Period:	7/9/2010 - 7/19/2010
Ballot Type:	Initial
Total # Votes:	262
Total Ballot Pool:	304
Quorum:	**86.18 % The Quorum has been reached**
Weighted Segment Vote:	65.93 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	90	1	42	0.575	31	0.425	4	13
2 - Segment 2.	9	0.4	2	0.2	2	0.2	4	1
3 - Segment 3.	74	1	33	0.569	25	0.431	9	7
4 - Segment 4.	22	1	9	0.6	6	0.4	4	3
5 - Segment 5.	54	1	27	0.675	13	0.325	5	9
6 - Segment 6.	35	1	17	0.63	10	0.37	2	6
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.4	2	0.2	2	0.2	2	1
9 - Segment 9.	6	0.6	6	0.6	0	0	0	0
10 - Segment 10.	7	0.5	5	0.5	0	0	0	2
Totals	**304**	**6.9**	**143**	**4.549**	**89**	**2.351**	**30**	**42**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Negative	
1	Ameren Services	Kirit S. Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Affirmative	View
1	American Transmission Company, LLC	Jason Shaver	Affirmative	View
1	Arizona Public Service Co.	Robert D Smith	Negative	View
1	Associated Electric Cooperative, Inc.	John Bussman		
1	Avista Corp.	Scott Kinney	Abstain	
1	Baltimore Gas & Electric Company	John J. Moraski	Negative	View

1	BC Transmission Corporation	Gordon Rawlings	Affirmative	
1	Beaches Energy Services	Joseph S. Stonecipher		
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	View
1	CenterPoint Energy	Paul Rocha	Negative	View
1	Central Maine Power Company	Brian Conroy	Negative	
1	City of Vero Beach	Randall McCamish	Negative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	View
1	Commonwealth Edison Co.	Daniel Brotzman	Negative	View
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Deseret Power	James Tucker	Affirmative	
1	Dominion Virginia Power	John K Loftis	Negative	View
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	E.ON U.S. LLC	Larry Monday		
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Negative	View
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Negative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Negative	View
1	GDS Associates, Inc.	Claudiu Cadar	Negative	View
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	View
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Negative	View
1	JEA	Ted E Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stan T. Rzad	Negative	View
1	Lake Worth Utilities	Walt Gill	Negative	
1	Lakeland Electric	Larry E Watt	Negative	View
1	Lee County Electric Cooperative	John W Delucca	Negative	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Manitoba Hydro	Michelle Rheault	Affirmative	
1	Metropolitan Water District of Southern California	Ernest Hahn		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	View
1	National Grid	Saurabh Saksena	Negative	View
1	Nebraska Public Power District	Richard L. Koch	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Negative	
1	New York State Electric & Gas Corp.	Henry G. Masti		
1	Northeast Utilities	David H. Boguslawski	Negative	View
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Douglas G Peterchuck	Affirmative	
1	Oncor Electric Delivery	Michael T. Quinn	Affirmative	View
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson		
1	Pacific Gas and Electric Company	Chifong L. Thomas	Affirmative	View
1	PacifiCorp	Mark Sampson	Affirmative	
1	PECO Energy	Ronald Schloendorn	Negative	
1	Platte River Power Authority	John C. Collins	Negative	View
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	
1	Potomac Electric Power Co.	Richard J Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery		
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	View
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Negative	View
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	View
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	

1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Abstain	
1	South Texas Electric Cooperative	Richard McLeon		
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	View
1	Southern Illinois Power Coop.	William G. Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Abstain	View
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association Inc.	Keith V. Carman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Negative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	View
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	View
2	Alberta Electric System Operator	Jason L. Murray	Negative	View
2	BC Transmission Corporation	Faramarz Amjadi	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Abstain	
2	Independent Electricity System Operator	Kim Warren	Abstain	
2	Midwest ISO, Inc.	Jason L Marshall		
2	New Brunswick System Operator	Alden Briggs	Negative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	Tom Bowe	Abstain	
2	Southwest Power Pool	Charles H Yeung	Affirmative	
3	Alabama Power Company	Richard J. Mandes	Affirmative	View
3	Allegheny Power	Bob Reeping		
3	Ameren Services	Mark Peters	Negative	
3	American Electric Power	Raj Rana	Affirmative	
3	Arizona Public Service Co.	Thomas R. Glock	Negative	View
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blue Ridge Power Agency	Duane S. Dahlquist	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	View
3	City of Bartow, Florida	Matt Culverhouse	Negative	View
3	City of Clewiston	Lynne Mila	Negative	
3	City of Green Cove Springs	Gregg R Griffin	Abstain	
3	City of Leesburg	Phil Janik	Negative	
3	Cleco Utility Group	Bryan Y Harper	Negative	View
3	ComEd	Bruce Krawczyk	Negative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Constellation Energy	Carolyn Ingersoll		
3	Consumers Energy	David A. Lapinski	Negative	View
3	Consumers Power Inc.	Roman Gillen	Abstain	
3	Cowlitz County PUD	Russell A Noble	Negative	View
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Negative	View
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Negative	View
3	Florida Municipal Power Agency	Joe McKinney	Negative	
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Negative	View
3	Georgia Power Company	Anthony L Wilson	Affirmative	View
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	View
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	View
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory David Woessner	Negative	
3	Lakeland Electric	Mace Hunter	Negative	View
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Los Angeles Department of Water & Power	Kenneth Silver		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C Parent	Negative	

3	MEAG Power	Steven Grego	Affirmative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	View
3	Mississippi Power	Don Horsley	Affirmative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	View
3	Muscatine Power & Water	John Bos	Affirmative	
3	New York Power Authority	Marilyn Brown	Negative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Negative	View
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	Ocala Electric Utility	David T. Anderson	Negative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters		
3	OTP Wholesale Marketing	Bradley Tollerson	Abstain	
3	PacifiCorp	John Apperson	Affirmative	
3	PECO Energy an Exelon Co.	Vincent J. Catania	Negative	
3	Platte River Power Authority	Terry L Baker	Negative	View
3	Potomac Electric Power Co.	Robert Reuter		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Abstain	
3	Public Utility District No. 2 of Grant County	Greg Lange	Negative	View
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	View
3	Salmon River Electric Cooperative	Ken Dizes	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Abstain	
3	South Carolina Electric & Gas Co.	Hubert C. Young	Affirmative	
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Springfield Utility Board	Jeff Nelson	Abstain	
3	Tampa Electric Co.	Ronald L Donahey	Negative	View
3	Turlock Irrigation District	Casey Hashimoto	Affirmative	
3	Umatilla Electric Cooperative	Steve Eldrige	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Negative	View
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	American Municipal Power - Ohio	Kevin Koloini	Abstain	
4	American Public Power Association	Allen Mosher	Affirmative	
4	City of Clewiston	Kevin McCarthy	Negative	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Negative	
4	Consumers Energy	David Frank Ronk	Negative	View
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards	Negative	View
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Affirmative	View
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	View
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	View
4	Seattle City Light	Hao Li	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	View
5	Chelan County Public Utility District #1	John Yale		
5	City of Grand Island	Jeff Mead	Abstain	
5	City of Tallahassee	Alan Gale	Negative	View
5	City Water, Light & Power of Springfield	Karl E. Kohlrus	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy	James B Lewis	Abstain	
5	Cowlitz County PUD	Bob Essex	Negative	View

5	Dominion Resources, Inc.	Mike Garton	Negative	View
5	Duke Energy	Robert Smith	Affirmative	View
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	View
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	JEA	Donald Gilbert	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink	Negative	View
5	Kissimmee Utility Authority	Mike Blough		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin	Affirmative	
5	Manitoba Hydro	Mark Aikens	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Negative	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	
5	New York Power Authority	Gerald Mannarino		
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Negative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Otter Tail Power Company	Stacie Hebert	Abstain	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	View
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Portland General Electric Co.	Gary L Tingley		
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	
5	PPL Generation LLC	Mark A. Heimbach	Negative	View
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	David Murray	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik		
5	Sacramento Municipal Utility District	Bethany Wright	Affirmative	View
5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	South California Edison Company	Ahmad Sanati		
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	South Mississippi Electric Power Association	Jerry W Johnson		
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	View
5	Tennessee Valley Authority	George T. Ballew	Affirmative	View
5	Tri-State G & T Association Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Negative	View
6	AEP Marketing	Edward P. Cox	Affirmative	View
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	View
6	Cleco Power LLC	Matthew D Cripps	Negative	View
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S Slade	Negative	View
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit		
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Affirmative	
6	Exelon Power Team	Pulin Shah	Negative	
6	FirstEnergy Solutions	Mark S Travaglianti	Negative	View
6	Florida Municipal Power Pool	Thomas E Washburn	Negative	View
6	Florida Power & Light Co.	Silvia P Mitchell	Negative	View
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Thomas Saitta		
6	Lakeland Electric	Paul Shipps	Negative	View
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	View
6	OTP Wholesale Marketing	Bruce Glorvigen	Abstain	
6	PacifiCorp	Gregory D Maxfield	Affirmative	

6	Progress Energy	James Eckelkamp	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	RRI Energy	Trent Carlson	Affirmative	
6	Salt River Project	Mike Hummel		
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak		
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	View
6	Western Area Power Administration - UGP Marketing	John Stonebarger	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8		James A Maenner	Abstain	
8		Roger C Zaklukiewicz	Negative	View
8	JDRJC Associates	Jim D. Cyrulewski	Abstain	
8	Pacific Northwest Generating Cooperative	Margaret Ryan	Affirmative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon	Negative	View
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	Oregon Public Utility Commission	Jerome Murray	Affirmative	
9	Public Service Commission of South Carolina	Philip Riley	Affirmative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Midwest Reliability Organization	Dan R. Schoenecker	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	View
10	ReliabilityFirst Corporation	Jacquie Smith		
10	SERC Reliability Corporation	Carter B Edge		
10	Southwest Power Pool Regional Entity	Stacy Dochoda	Affirmative	
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement
Initial Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Project 2007-07: Transmission Vegetation Management
The initial ballot for proposed standard FAC-003-2 — Transmission Vegetation Management ended on July 19, 2010.

Ballot Results
Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 86.18 %
Approval: 65.93 %

Since at least one negative ballot included a comment, and the affirmative votes did not meet the threshold for approval, these results are not final. Another comment and ballot period will be conducted.

Violation Risk Factor (VRF) and Violation Severity Level (VSL) Non-binding Poll Results
Only 6% of the non-binding polls for VRFs and VSLs were returned, rendering the results inconclusive. By comparison, the Underfrequency Load Shedding, Protection System Maintenance and Testing, Backup Facilities, and Transmission Loading Relief standards all had greater than 80% of the non-binding polls for VRFs and VSLs returned with an opinion.

Next Steps
The drafting team must draft and post responses to comments received through the public comment period and the initial ballot. The response to comments and proposed revisions will be posted for a 30-day comment period, and a "successive ballot" will be conducted during the last ten days of that 30-day comment period. A non-binding poll of the proposed VRFs and VSLs will also be conducted during the last ten days of the 30-day comment period.

Project Background
The project is an update to FAC-003-1, which was approved in 2006. The items identified for revision include the incorporation of FERC Order 693 comments related to applicability, procedural repairs to conform to the current standards format and development procedure, technical updates and guidance to address stakeholder suggestions, and the elimination of "fill-in-the-blank" components.

More information is available on the project page: http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

The NERC Standards Committee endorsed the use of Project 2007-07: Vegetation Management as the prototype for the proof-of-concept for using the "results-based" criteria for developing a reliability standard. The overall approach includes considerably more emphasis on the "concepts and assumptions" underlying the development of requirements and goes beyond the steps most drafting teams use when developing a standard. Accordingly, the "look and feel" of the vegetation management standard is quite different than NERC's existing standards. However, at the core is a set of mandatory and enforceable requirements with useful guidance supporting these requirements, an approach NERC's legal counsel has reviewed and finds acceptable. More information about results-based standards can be found at: http://www.nerc.com/filez/standards/Project2010-06_Results-based_Reliability_Standards.html

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Ballot Criteria

Approval requires both a (1) quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention, and (2) A two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and nonresponses. If there are no negative votes with reasons from the first ballot, the results of the first ballot shall stand. If, however, one or more members submit negative votes with reasons, a second ballot shall be conducted.

For more information or assistance,
please contact Lauren Koller at Lauren.Koller@nerc.net

Individual or group. (44 Responses)
Name (28 Responses)
Organization (28 Responses)
Group Name (16 Responses)
Lead Contact (16 Responses)
Question 1 (43 Responses)
Question 1 Comments (44 Responses)
Question 2 (41 Responses)
Question 2 Comments (44 Responses)
Question 3 (42 Responses)
Question 3 Comments (44 Responses)
Question 4 (43 Responses)
Question 4 Comments (44 Responses)
Question 5 (42 Responses)
Question 5 Comments (44 Responses)
Question 6 (40 Responses)
Question 6 Comments (44 Responses)
Question 7 (38 Responses)
Question 7 Comments (44 Responses)
Question 8 (43 Responses)
Question 8 Comments (44 Responses)

Individual
David Burke
Orange and Rockland Utilities, Inc.
Yes
There should be a statement in Table 3 that is consistent with footnote number 2 stating that the minimum width of the Active Transmission Line ROW is either the full width of the easement or, if the easement is wider than the distances in Table 3, the minimum distances must not be less than the distances shown in the Table.
Yes
Yes
Yes
Yes
Draft 4 version of R1/R2
Orange and Rockland Utilities, Inc prefers the Draft 4 version. The wording in the VSLs should be modified for both Requirements to include the phrase 'manage vegetation.' The phrase 'manage vegetation' requires a utility to take specific action to prevent encroachments/outages.
VSLs proposed by the VM SDT
The wording in the VM STD VSLs should be modified to include whether or not the TO managed any vegetation on that particular line. A more severe VSL should be assigned to any encroachment or sustained outage that was caused as a result of a TO not performing any vegetation management activities on that line. For example, if vegetation management activities were completed on 80% or 90% of the line and additional work was in progress on the remainder of the line but an encroachement or sustained

outage occurred on the spans that were scheduled to be done as part of the annual plan, the TO should be held accountable for this but at a lower severity level.
Yes
In R5, the SDT should better define the phrase 'where a transmission line is put at potential risk due to the constraint.' This is rather vague and could lead to inconsistent practices between utilities. Orange and Rockland Utilities, Inc. defines all undesirable species on the full width of the ROW as 'potential risks to the transmission line' regardless of height or location at the time of vegetation management. Interim corrective action should only be required when the potential risk is approaching the imminent threat classification.
Group
Western Area Power Administration
Brandy A. Dunn
Yes
Suggest using a total right-of-way width in Table 3 rather than a distance measured from centerline.
Yes
Yes
However, the last sentence added to the measure is imprecise and introduces undesirable subjectivity and confusion to the process for determining a compliance violation.
Yes
No
As the list of â€œexamples of reasons for modificationâ€☐ is not all inclusive, it is unnecessary and could result in confusion regarding compliance when a scenario other than one listed requires a change. Further, documentation of changes to the annual plan adds unnecessary administrative burden which is inconsistent with a performance based standards approach.
Draft 4 version of R1/R2
The current language of Draft 4 is the most flexible and offers industry the best opportunity for executing a cost effective and efficient program.
VSLs proposed by the VM SDT
Unlike a â€œgrow-inâ€☐, a â€œfall-inâ€☐ or â€œblow-inâ€☐ has never caused or contributed to a cascading outage. Further, the â€œzero toleranceâ€☐ approach of this standard remains impractical and unreasonable. The gradated indicators of program performance associated with a â€œfall-inâ€☐, â€œblow-inâ€☐ and â€œgrow-inâ€☐ offer some measure of reasonableness to the requirement.
No
Group
Northeast Power Coordinating Council
Guy Zito
No
There should be a statement in Table 3 that is consistent with footnote number 2 stating that the minimum width of the Active Transmission Line ROW is either the full width of the easement or, if the easement is wider than the distances in Table 3, the minimum distances must not be less than the distances shown in the Table. The use of a minimum distance from the centerline of the circuit or structure is an incorrect measure to use for a set clearance distance of the active transmission right-of-way. The description does not take into account vertical versus horizontal

design configuration. Consideration should be given for the type of construction as different construction types (H-Frame, Lattice towers, Monopole delta or vertical construction) will require different widths of a cleared right-of-way to provide the necessary openings for these circuits. A minimum distance for 345-kV is now set at 150 feet based on the minimum distances from centerline. This may be correct for certain H-Frame and Lattice Tower configurations but it is excessive for monopole situations. A single pole configuration with vertically aligned conductors does not need this full 150 foot width. It is strongly recommended that a minimum distance from conductor be used in place of a set distance from centerline. As long as there is at least 30 - 40 feet of clearance in the right-of-way from the outermost conductors (adjusted to account for maximum sway at mid-span for longer spans), then this is the distance that should be used to develop the right-of-way widths. For example, a monopole structure with vertically aligned conductors would result in a cleared active right-of-way width of only 80 feet (40 feet from conductor to edge of cleared active right-of-way) using the minimum distances from the conductors. There is no need to extend this distance another 35 feet (on each side) in order to obtain the full 150 foot width. This requirement is excessive and must be adjusted to account for line construction variations. Instead of using the term "Centerline" as referenced on Table 3, the use of "outer phase" or "phase closest to tree line" would be more appropriate. There is published literature using the term â€œcleared widthâ€□ to indicate the distance from the outer phase to the tree line. This distance should be used in the Active ROW definition. The word easement is also used in the definition. Is there a reason the Active ROW only includes easements, not fee ownership, license or some other right to occupy and manage the ROW? Would Active ROW include â€œdanger tree rightsâ€□ on land? These questions need to be addressed in the standard (in text) and technical reference document (in graphics).
Yes
No
A clarification for M1 is needed regarding whether entities will have to attest to the fact that there has never been an encroachment in the MVCD.
Yes
Yes
Alternate version of R1/R2
Alternate Version E would allow a Transmission Owner to use an approach consistent with the current version of FAC-003 by defining a minimum clearance distance and a vegetation management clearance distance. This approach has met the objectives of FAC-003 since 2006. Use of version E would change the standard from a prescriptive approach to a Transmission Owner defined approach. In addition, Alternate Version E is preferred as it allows for variations based on differences in conductor heights, topography and other situations where a set height is not necessarily required in all instances and allows for the utility to determine the maximum heights of vegetation without performing detailed calculations of what the maximum heights must be along the various distances within each conductor span. If the utility is tasked with managing the vegetation to ensure no encroachments into the MVCD then it should be up to the individual utility how best to determine its management strategies that incorporate the determination of maximum vegetation heights in each section on its system.
VSLs proposed by the VM SDT
The wording in the VM STD VSLs should be modified to include whether or not the TO managed any vegetation on that particular line. A more severe VSL should be assigned to any encroachment or sustained outage that was

caused as a result of a TO not performing any vegetation management activities on that line. For example, if vegetation management activities were completed on 80% or 90% of the line and additional work was in progress on the remainder of the line, but an encroachment or sustained outage occurred on the spans that were scheduled to be done as part of the annual plan, the TO should be held accountable for this but at a lower severity level.
Yes
NPCC wants to thank the SDT for the effort that has gone into developing this proposed revision to FAC-003. Overall the new version is consistent with FERC Order 693 and will be a straightforward, workable, and auditable standard. One item requiring clarification and change is the Active ROW definition. The recent addition of a centerline distance to edge of Active ROW is not acceptable. In many areas design standards allow a smaller ROW width with no compromise to â€œcleared widthâ€□ or tree related reliability of the line. The SDT needs to address this issue. In R5, the phrase 'where a transmission line is put at potential risk due to the constraint' should be better defined. This is vague and could lead to inconsistent practices between utilities. All undesirable species on the full width of the ROW are defined as 'potential risks to the transmission line' regardless of height or location at the time of vegetation management. Interim corrective action should only be required when the potential risk is approaching the imminent threat classification.
Individual
Weston Davis
Central Maine Power Company, Iberdrola USA
No
Table 3 distances may not be appropriate, for example table 3 should reflect a clearance zone based on construction type, topography, species, or growth rates. Table 3 could give the impression that the listed distances are the maximum, therefore suggest table 3 be removed or revised. The Active Transmisson Line Right-of-Way defination uses the word easement, which most likely would include danger trees in situations where danger removals are included in the the easement language. This would expand the scope of FAC 003 2 beyond the cleared right-of-way width.
No comment suggested.
No
Recommend SDT create two measures one measure if a tree violated the MVCD and no outage occurred and second measure and severity level if an outage occurred
Yes
Yes
Alternate version of R1/R2
VSLs proposed by the VM SDT
Agrees with SDT that violation risk factors must be ranked in accordance with impact on the bulk delivery system.
No
Individual
Kasia Mihalchuk
Manitoba Hydro
Yes
Please add metric equivalents in the standard. While it makes some aspects easier around pointing to what we need to keep "clear" to meet

NERC rules - it does limit some of our flexibility to design lines and ROWs to your own standards. Also, the minimum only applies when you have easement larger than the minimums in table 3, and I would assume that does not relieve you of the responsibility to maintain ROWs appropriately if the design of your lines requires a wider ROW.
Yes
Yes
Yes
Yes
Draft 4 version of R1/R2
I would suggest adding verbage to the draft 4 version to explicitly include the sag and sway of the conductor to the concept of "operating within rating and electrical operating conditionâ€œ
VSLs proposed by the VM SDT
No
Individual
Jonathan Appelbaum
The United Illuminating Company
No
The definition has been altered. The last sentence "However, it is not to be less than the width of the easement itself unless the easement exceeds distances as shown in Table 3 for various voltage classes..." was added. The concept of the easement is confusing and not included in the Supplemental Reference. Table 3 of the standard is titled "Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW", no mention of easements. It is suggested that the definition state "strip or corridor of land that is occupied by active transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities. At a minimum the width is to be the distances as shown in Table 3 for various voltage classes." The proper location for the definition is in the Glossary.
Yes
Yes
Yes
No
R1 and R2 are requirements that no encroachment occurs. R7, as proposed, requires a VMP to be completed to ensure no encroachment occurs. The Supplemental Reference for R7 does not describe the requirement of the annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. The Reference states the requirement is established to diminish the risk of encroachment; which is very different from ensuring no encroachment. In the Reference for R7 the word â€œensureâ€☐ is only used to describe that flexibility in the VMP is allowed to ensure the reliability of the Transmission System. M7 is measuring work plan completion not the prevention of encroachment. United Illuminating suggests that R7 be changed to: Each Transmission Owner shall complete the work in an annual vegetation work plan to manage the prevention of vegetation encroachments occur within the

MVCD. In this way, a violation of R1/R2 does not necessarily mean R7 is violated. The entity does not avoid a penalty for an encroachment because a violation of R1/R2 occurs for actual encroachment. If an encroachment occurs the compliance enforcement authority can review the entities vegetation management plan to determine if it is compliance with R7/M7.
Draft 4 version of R1/R2
UI prefers the draft language because we believe the intent of R1/R2 is to capture the actual occurrence of a vegetation related interruption or encroachment of vegetaion into the MVCD based on actual conditions.
VSLs proposed by NERC staff
United Illuminating agrees with NERC Staff that the Requirement is to prevent encroachment of any kind. Differentiating between fall-in and grow-in is of no consequence to the intent of the requirement.
Yes
R4: In R4 the phrase: without any intentional time delay, is a concern. There is a time line between identification and reporting of an imminent hazard that represents the minimal time required to complete this Requirement. Any situation where the time between observation and reporting is greater than this minimal time line indicates a time delay occurred. It will be left to the compliance enforcement authority to determine if this delay was intentional or not. It is not proper for the test to be based on Intentional versus Non-Intentional. Using other synonyms such as reasonable, expeditious, prompt, immediate or without hesitation all introduce a qualitative not a quantitative attribute to the measurement. The Supplemental Reference for R4 indicates that the imminent threat requirement is measured in minutes or hours; again no guidance for enforcement. R4 would be improved with an explicit time requirement of 6 hours between observation and report. This is measurable and clear. R4 should be: Each Transmission Owner shall notify the control center holding switching authority for the associated transmission line no more than 6 hours of a qualified personnel confirm the existence of a vegetation condition that is likely to cause a Fault at any moment. Other commenterâ€™s will argue that 6 hours is arbitrary or unduly prescriptive. I believe it is in line with the Supplemental Reference and adds clarity to the enforcement process. M4 becomes Each Transmission Owner that has a vegetation condition likely to cause a Fault at any moment, as confirmed by qualified personnel, will have evidence that it notified the control center holding switching authority for the associated transmission line within 6 hours of observation. The Transmission Owner can use the inspection as evidence of the time of observation. Effective Dates: The effective dates in the implementation Plan is in a different form then UI was expecting. Effective Date 1 UI has no comment. Effective date number 2 implies that if the BOT approves the standard and FERC takes no action (neither approves, remands or withholds approval of the standard) then the standard will become effective in one year. This seems to create the possibility of an effective standard without enforceability. Effective Date number 3 implies that regardless of any action by FERC the standard will become effective at least one year following BOT approval. Again this creates an effective standard without enforceability. Also the use of â€œat least one yearâ€☐ does not add any clarity to when the Standard would be effective any way.
Individual
Patrick Simons
Idaho Power Company
No
The way I interpret this, the new definition of active transmission line right of way takes away our ability to clear potential fall ins if they are outside of the active transmission line ROW>
Yes

Yes
Yes
Yes
Alternate version of R1/R2
I think this gives us more flexibility to maintain our clearances.
VSLs proposed by NERC staff
Yes
I would like to see something more from NERC to clear the way for utilities to do vegetation management on federal lands that will allow timely vegetation management without delays from these federal entities.
Individual
Sam Stonerock
Southern California Edison Company
Yes
SCE appreciates the SDTâ€™s efforts to replace the defined term with a set of minimum distances. However, the proposed new Table 3 appears to assume a horizontal configuration of transmission lines. Thus, it would appear that those lines configured vertically (for example, two circuits on opposite sides of a tower), the â€œactive right of wayâ€☐ required would be at least twice as large as that for horizontal lines. SCE respectfully recommends a footnote be added to Table 3 that allows the TO to recalculate the active right of way for lines in a vertical configuration, based on a horizontal line configuration.
Yes
SCE generally agrees with the information contained in Part 5 â€“ Background. However, we question the value of placing a rationale within the body of the standard. SCE respectfully recommends that the revised â€œBackgroundâ€☐ information be added to the beginning of the â€œGuidelines and Technical Basis,â€☐ which also includes explanations for various standard segments.
Yes
SCE generally agrees with the revisions to M1 and M2, however we would suggest the last sentence of the second paragraphs in both M1 and M2 be modified to read: M1- Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. If an investigation of a Fault, by a qualified person, confirms that a vegetation encroachment, as described in R1 items 2-4 (above), occurred within the MVCD occurred, then it shall be considered a Real-time observation. M2- Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. If an investigation of a Fault, by a qualified person, confirms that a vegetation encroachment, as described in R2 items 2-4 (above), occurred within the MVCD occurred, then it shall be considered a Real-time observation.
No
SCE prefers the Draft 3 version of R3 which read: â€œEach Transmission Owner shall have a documented transmission vegetation management program that describes how it conducts work on its Active Transmission Line ROWs to avoid Sustained Outages due to vegetation, considering all possible locations the conductor may occupy assuming operation within Rating and Rated Electrical Operating Conditions.â€☐ However, if the SDT believes it is prudent to revise R3 in response to certain commenters, SCE would respectfully recommend R3 be revised to read: â€œEach

Transmission Owner shall document the procedures, processes, or specifications it uses to prevent the encroachment of vegetation into the MVCD. Such documentation will account for the movement of transmission line conductors under their Rating and Rated Electrical Operating Conditions; and the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the Transmission Ownerâ€™s applicable lines.â€□
Yes
SCE agrees with the revisions to R7, but notes the some minor edits to the text are still needed.
Alternate version of R1/R2
SCE prefers the operational flexibility provided by the alternate version of R1/R2. We also note that dating back to development of FAC-003-1 and related comment periods, Transmission Owners have repeatedly stated that a â€œone-size-fits-allâ€□ TVMP is not viable or reasonable.
VSLs proposed by the VM SDT
SCE agrees with the SDT's rationale and proposals for VSL Criteria.
Yes
SCE questions the need for including the â€œGuidelines and Technical Basisâ€□ section within the body of the standard and is also curious as to the criteria used in developing new Table 3. SCE finds this Draft (4) to be the best work product thus far, and commends the SDT for its efforts and continued dedication to crafting a best-in-class standard.
Individual
Marty Berland
Progress Energy
No
In Applicability Section 4.4, â€œactive transmission line ROWâ€□ is not capitalized indicating it is not a defined term, but Footnote 2 is effectively a definition for active transmission line ROW. However, in the first paragraph of Section 5 Background, Active Transmission Line Right-of-Way is capitalized indicating itâ€™s a defined term. It would seem cleaner to make â€œActive Transmission Line Right of Wayâ€□ a formal NERC definition. Alternatively and at a minimum, Footnote 2 should be revised to say â€œAn active transmission line ROW is a strip or corridorâ€¦â€□ and also in Section 5 Background, â€œActive Transmission Line Right of Wayâ€□ should be changed to no longer be capitalized.
Yes
Yes
Yes
Yes
Yes
1) On p. 3 of the redline, the table of Effective Dates is struck out, but the key (listed as 1, 2, 3 below the table: â€œ1. First calendar dayâ€¦â€□) remains but now the numbers 1, 2, and 3 no longer refer to the table of Effective Dates as the table has been struck. 2) The first paragraph under â€œExceptionsâ€□ could be reworded to be clearer. As currently proposed, it states lines below 200kV become subject to the standard 12 months after the lines are designated as being subject to the standard, which is somewhat circular. We propose instead: â€œA line operated below 200kV becomes subject to this standard 12 months after the date

the Planning Coordinator or WECC initially designates the line as an element of an IROL or as a Major WECC transfer path.â€☐ 3) Applicability Section 4.2.4 says the standard does not apply to Facilities located in the fenced area of a switchyard. However, p. 8 in Section 5 Background says the standard does not apply to underground or submarine lines or line sections inside a station boundary. Two things should be addressed to make these consistent: â€œFacilitiesâ€☐ is a NERC-defined term that includes more than just lines, and includes lines, generators, compensators, transformers, etc. Also, is the â€œstation boundaryâ€☐ always defined by the fenced area? Any potential conflict due to this inconsistency should be resolved. 4) In the redline of Draft 4, in R5 and M5, the word â€œinterimâ€☐ is struck through. However, the Rationale box says â€œâ€¦.the intent is for the Transmission Owner to put interim measures in placeâ€¦â€☐ The use of â€œinterimâ€☐ should be consistent between R5, M5 and the Rationale box. 5) R6 requires the TO to perform Vegetation Inspections â€œat least once per calendar yearâ€☐. There could potentially be future interpretation requests that question whether â€œonce per calendar yearâ€☐ means performance sometime during each year (i.e. 2010, 2011, etc.), or whether no more than 365 calendar days can elapse between inspections. The first interpretation could allow up to almost 2 years to elapse between inspections even when doing it â€œonce per calendar yearâ€☐. This should be clarified.
Individual
John Bee
Exelon
No
The term â€œCenterline of the Circuitâ€☐ in Table 3 is not defined. Until it is defined, there is no way to know if the standard is technically reasonable or whether existing circuits would be in violation of the standard and unable to operate. In addition, it is unclear what types of construction and span lengths were used to develop the distances for active right-of-way widths in Table 3. Furthermore, it is not clear whether Table 3 contains requirements against which compliance will be measured or best practice guidelines. Footnote 2, in the background section, compounds this ambiguity. In short, the lack of a definition for â€œCenterlineâ€☐ combined with Footnote 2 and Table 3 make this draft unclear and unenforceable. Exelon does not necessarily have easement widths for all transmission lines that equal those defined in Table 3 of this draft; This may require the acquisition of additional easements, if even possible.
Yes
Yes
Yes
Yes
Draft 4 version of R1/R2
VSLs proposed by the VM SDT
No
Individual
Hugh Conley
Alleghney Power
No

Allegheny Power strongly disagrees with the numbers or widths stated within Table 3. These numbers seem arbitrary and have no accompanying reasonable explanation as to their origin, basis, or other criteria noting the rationale for inclusion in this standard. This inclusion effectively prohibits a TO from establishing corridor widths less than the widths (which may be easily possible by utilizing various tower or structures heights or configurations) stated in Table 3 without placing the TO in extreme jeopardy of non-compliance issues from a falling off-corridor tree, during minor storm conditions as an example. Furthermore, this Table insinuates the TO has no ability to successfully manage vegetation WITH NO RESULTING OUTAGES or encroachments within the MVCD from off-corridor trees where corridors are less that the widths stated in Table 3. Allegheny Power suggests that the definition of the â€œActive Transmission line Right Of Wayâ€☐ be â€œthe transmission line ROW corridor that is actively maintained as part of the entity's vegetation management plan.".
Yes
Yes
Yes
Yes
Alternate version of R1/R2
Allegheny Power prefers the alternate version.
VSLs proposed by the VM SDT
No
Individual
Edward Davis
Entergy Services
No
This is very unclear, and creates much uncertainty as to how certain potential outage situations should be reported. Clarification language should be added within the Standard to help define and guide the TO's actions when an outage occurs from a location at a point that is less than the documented ROW boundaries (Easements) but greater than the ROW distances represented in Table 3. It is unclear which distance should guide our reporting actionsâ€¦â€¦..ROW Document Width, Table 3 ROW Widths, or the lesser of the twoâ€¦â€¦. See scenarios / examples below for consideration to aid with clarification points: Example 1: If our documented ROW width for a 500kV line is 100' from centerline (200' total ROW width) and we have a fall in from 90' from centerline, do we report this as a Category 2 Outage due to the fact that it fell from within our ROW limits, or is it non-reportable due to the fact that it is located at a greater distance than 87.5' from the centerline of the ROW as listed in Table 3 in the Standard? Example 2: How does maintenance and outage reporting correlate with the example defined as followsâ€¦â€¦.You have a 230 kV line situated on one side of a 150' wide ROW that was initially cleared to a width that would accommodate 2 separate parallel transmission lines and structures. The second set of lines/structures have not yet been constructed, and the current Transmission line is situated on one side of the 150' ROW, and is being maintained to the edge of the actual ROW on the side of the ROW that it was constructed on (maintained to a distance of 50' from centerline that puts it at the legal edge of the ROW), but it has been typically maintained to a distance of approximately 60' from centerline to the inside portion/other side of the ROW (the side of the ROW

that has never been cleared), but a tree falls into the line from approx 58' from centerline (2' within the 60' distance typically being maintained on that line)â€¦â€¦.would this be considered a Category 2 outage since it was approx 2' within the average width being maintained on that side of the ROW or would it not be reported due to the fact that it was located at a distance greater than 50' as indicated in Table 3??
Yes
Yes
We agree, IF the determination is made by a Qualified Person to have been caused by vegetation breaking the MVCD (if not breaking MVCD in real time when observed) based on close observation/inspection and hard evidence that a Flashover occurred, and that there is no evidence that the issues spotted on the tree were caused by environmental or biological symptoms or stressors of the tree in question. Hard evidence has to be present to classify the item as a vegetation outage if the tree is not within MVCD when the real time observation is madeâ€¦..an assumption cannot be made that vegetation was the cause of an outage if the tree is situated at a distance that is greater than MVCD when observed unless there is hard evidence supporting the flashover as determined by a qualified person.
Yes
Yes
Draft 4 version of R1/R2
Draft 4 is acceptable, but if alternate language is chosen, it should be similar to option E, keeping the determination simple and with as few variables for interpretation as necessary.
VSLs proposed by the VM SDT
This gives the option to activate and follow the Imminent Threat Process if a breach of the MVCD is located and reported for isolated events absent a sustained outage. It gives the TO the opportunity to mitigate the issue when it is identified and corected prior to experiencing an outage..
Yes
ITEMS of concern listed below: ITEM 1: Page 13 of the Standard Draft 4 under Add'l Compliance Information - Periodic Data Submittalâ€¦â€¦Clarify if Immediate Reporting is expected for outages in Outage Categories 1A, 1B, 2, or 4â€¦â€¦..or if Quarterly Reporting is all that is expected. It does not specifically say that IMMEDIATE Reporting is Required for any outage type. It is assumed that IMMEDIATE reporting is required for some outages, but is unclear. ITEM 2: Agree that text boxes being used for additional clarity is a benefit if used in a correct and clear manner, but it needs to be specifically stated in the document that the text boxes are to be used for reference only, we will not be required to specifically follow the language in the rationale, and that and each utility should specify their own exact process for addressing each Requirement. ITEM 3: Language should be added to the Guideline and Technical Basis Section to clarify or re-state that this section that this section is for assisting entities in understanding how to comply with the standard but does not contain mandatory actions/activities. ITEM 4: Please clarify defining factors that constitute "wind shear or fresh gale" as referenced in Section 4.4 Other. This is a very unclear interpretation and will most likely be interpreted differently by all involved if not specified.
Individual
Jon Kapitz
Xcel Energy
No

We believe Active Transmission ROW should be a defined term, not buried in a â€œfootnoteâ€ of the â€œOtherâ€ section of a Standard. It still begs the question â€“ what is an â€œactive transmission facilityâ€? Regarding the substance, overall we believe that the Active Transmission ROW should not include the new reference to Table 3. This newly added sentence in footnote 2, referencing Table 3, is confusing to interpret. If retained, please rephrase to make it clearer that a Transmission Owner never has to increase the size of its easement/land right to satisfy this table. As drafted, our team had various interpretations and it is unclear whether the intent is that a Transmission Owner has to increase its easement or acquire land to meet this requirement, or conversely if the easement is well beyond the values in Table 3, the Transmission Owner has to maintain that the entire easement or only the values in Table 3. â€œActive Transmission Right of Wayâ€ is still used in the first paragraph of the Background section. In total, we suggest that the definition of Activate Transmission ROW return to the version used in the prior draft and be placed in the definition section.
No
Xcel Energy urges the retention of the word "reasonable" as a modifier to "control" in Introduction, Section 4.4. The concept that a Transmission Owner should exercise reasonable control is sensible, and is of some aid in countering claims that any incident could be prevented. For example, in Colorado, the transmission of electricity has been judicially found to be subject to the highest degree of care. Without the inclusion of the word "reasonable," Xcel Energy could possibly be faced with a claim that for the exceptions set forth in Introduction, Section 4.4, to apply, the circumstances would have to be "beyond the control (using the highest degree of care) of Xcel Energy." Retention of "reasonable" helps counter such claims. Since this section appears to lean toward legal language, the use of the term â€œreasonableâ€ is better suited for the goal of this section.
No comments/no position
No
R3 requires the Transmission Owner to have a documented process that shall contain certain items. Please bulletize these items for clarity. Additionally, the measure for this requirement indicates that the process document elements â€˜preventâ€™ encroachment. It is presumed that the elements identified in the requirement are what need to be addressed in order to minimize the likelihood of encroachment. Essentially, M3 should be reworded to state â€œThe procedures, processes, or specifications provided incorporate the elements identified in R3 (dynamics of a transmission line conductorâ€™sâ€¦)
No
What exactly does complete an annual work plan mean? It infers that an annual work plan must be developed/documented and executed. If this is the case, then clearly state as such. In general, R6 & R7 go against the grain of the results based standard concept. R1 already established that the Transmission Owner cannot have encroachment. R3 requires annual inspection (essentially establishing the plan). Why replicate in R6 & R7, it does not seem to serve any useful purpose.
Draft 4 version of R1/R2
Any of the alternate versions would amplify or create issues between land owners and Transmission Owners and are contrary to concepts of Integrated Vegetation Management, in particular, best management practices.
VSLs proposed by the VM SDT
Yes
R1 & R2 states that â€œtypes of encroachments include:â€ â€“ is the way this is worded intended to imply there can be other types of

encroachments that are not listed? If not, then rephrase the leading sentence to be definitive and indicate that the types are the only categories to be considered. We suggest that the wording from the prior draft, i.e., â€œ . . . limited toâ€□. MCVD should be a defined term in the glossary, not in a â€œRationaleâ€□ box. R1 â€œ1â€□ should Real-time be capitalized to reflect the glossary definition? The term is used as â€œreal timeâ€□, â€œReal timeâ€□ and â€œReal Timeâ€□ throughout the standard. This seems to be just a drafting issue, but the same term should be used consistently. Need to establish somewhere that the entity defines what constitutes a â€œqualifiedâ€□ person. Further, some portions of the standard use the term â€œqualified personâ€□ (e.g., see M1) and others reference â€œqualified field personnelâ€□ (e.g., see the Rational Box near M3). It seems that all references should be to â€œqualified field personnel.â€□ R1 & R2 are duplicative. It appears the only reason for the separation is so that different VRFs can be assigned. Why not just have 1 requirement and indicate that the VRF is High for one set of lines and Med for others? In general, the â€œRationaleâ€□ boxes force the requirement language into a difficult to read format. R5/M5 â€“ the measures identified do not constitute â€œcorrective actionsâ€□, they merely identify documentation that work was attempted. Corrective actions should be â€œactionsâ€□, such as establish an increased monitoring plan, re-rating of the line, removal from service, etc. R6 â€“ Xcel Energy still believes the requirement in R6 that mandates an annual inspection is too onerous and is at odds with the results-based approach of these revisions. Xcel Energy urges the retention of the provision in the existing standard that allows the Transmission Owner to set the frequency of inspection. In some areas of the country, annual inspections may not be adequate. Yet in other areas, a longer inspection frequency may be perfectly reasonable and practical. Our point is that inspection frequency should not be treated as if it were â€œone size fits allâ€□. If treated this way, we feel this could pose a risk to reliability and is not likely to be cost-effective. The Transmission Owner should be allowed some flexibility. However, if the drafting team disagrees and determines that an annual inspection is to be mandated, Xcel Energy believes that an exception to the annual inspection is appropriate when a non-subjective advanced technology such as LIDAR is utilized to achieve actual clearance distances. This places the Transmission Owner in a situation where it can rationally determine that the objectively measured distances result in a situation where an inspection need not be performed within the next year. It is suggested that R6 be revised to read as follows: Each Transmission Owner shall perform a Vegetation Inspection of all applicable transmission lines at least once per calendar year, unless the Transmission Owner, based on a non-subjective advanced technology, such as LIDAR, determines that a longer inspection period is appropriate. The Effective Dates section is confusing â€“ exactly when would this standard be in effect? It lists 3 approvalsâ€¦do all three have to be met or just one? The reference to Major WECC transfer paths in the requirements introduces a weak element. The WECC major path designation and elements that comprise those paths should be controlled through a robust process and easily available to WECC members. Currently, there are some concerns around that process in general. NERCâ€™s concerns regarding reporting vegetation related outages within 48 hours should be addressed or clarified in the Compliance section. (i.e., incorporate or indicate that this supersedes that recommendation). Ref: Public Notice - NERC Compliance Process #2008 â€“ 001
Individual
Gordon Rawlings
BC Hydro
No
The footnote definition is ok but Table 3 is poorly developed. The voltage classes should be better segregated (e.g. nominal voltage 69kV, 138kV,

230kV, 287kV, 345kV, 500kV, 765kV) along with distances in feet and metres as Canadian utilities are metric. Also the table should include recommended right of way widths for single circuits. The assumption made in the footnote is that the legal easement is larger than in Table 3. However, as currently defined, some of the distances in Table 3 exceed statutory rights of way at our utility and exceed engineering standards as defined by the Canadian Standards Association â€“ Overhead Systems (CAN/CSA C22.3 No. 1-6). Also, clearances will very much depend on line design (e.g. structure architecture such as flat, Post T, H-frame, steel lattice, and other variables such as ruling span length, conductor type used, etc.) To some degree this will vary quite a bit between utilities. As such Table 3 as currently presented is not workable.
Yes
Yes but there should be more commentary around exceptions. You should get away from certain descriptive terms and be more empirical when you can to avoid ambiguity. For example â€œFresh Galeâ€☐ on the Beaufort Scale is not common as there are several variants to this scale and on some scales is defined as â€œGaleâ€☐. So do you mean winds of 39-46 mph (62-74 kmh) or greater wind speed? If so, why not state that?
No
Overall, the definition of these measures is improved over draft 3. However, the standard should better define who a â€œqualified personâ€☐ is and who has the authority to make attestations. R1 and R2 could be better defined relative to the standard definitions in section 4.2 as to what voltage levels in R2 are part of the standard and what is excluded. That is: R1 is any circuit that is an element of an IROL or WECC transfer path regardless of the transmission voltage. R2 is any circuit >200kV which is not an element of an IROL or WECC transfer path. Lower voltage circuits that do not fit the R1 definition are not part of this standard.
Yes
As a competency requirement, R3 seems to be missing any requirement for a utility to define who is qualified to develop these plans, which is a departure from FAC-003-1 R1.3. I think that the utility should in their standards define who is qualified to develop their transmission vegetation management program
Yes
The requirement as currently worded, seems to assume but does not explicitly state that a utility must prepare and document an annual vegetation work plan and document in some manner any modifications to that work plan as they occur. The work plan change documentation should include any risks of work deferral and mitigation plans to address those risks if there are any.
Draft 4 version of R1/R2
The alternatives above are too prescriptive. A utility should set a preferred maintenance distance (i.e. clearance 1 in FAC-003-1) as routine expectation and outline mitigation strategies as required in areas where clearance 1 distances cannot be met to ensure that MVCD distances are not encroached upon. Given the various line design standards, it is the utility that must define those clearances and margins of error based on engineering standards and the types of vegetation and growth rates present in their operating area.
VSLs proposed by the VM SDT
The NERC staff recommendation is too restrictive and does not seem realistic in an operational sense. We do not agree that the standard should apply to outages from vegetation falling into the conductor from within the active transmission right of way. This normally would not occur except during storm events that would be excluded from this standard. It is operationally difficult to know precisely where the edge of the right of way is in all situations and under all conditions. Further, in clearing some sections to this degree, the utility could end up destabilizing what is

currently a stable, windfirm edge and pose higher security risks to the transmission system from destabilizing the vegetation through excessive clearing. So this gets down to semantics of how a utility might define their active right of way corridor relative to the legal statutory right of way edge. The risk of fall into outages needs to be managed but as currently defined this is too absolute a requirement. Fall-into outage risks need to be mitigated but they have not been a key element of any cascading failure and are hard to prevent. Even if a right of way were cleared sufficiently wide to avoid a fall-into outage, there is always a risk of branches being blown into the conductors from sailing during higher winds (e.g. Douglas-fir branches have excellent airborne gliding abilities). The greatest risk is from grow-into outages or from conductors and vegetation being blown into one another within the active right of way. Therefore, we prefer the VSLs set by the VM standard development team.
Yes
R4 â€“ There will likely be issues of definition over what constitutes an â€œintentional delayâ€□ in notification. The time for reasonable reporting needs to be quantified. The standard references Tables 2 and 3 but there is no Table 1 in the document. This is confusing and should be renumbered. This is likely a carry over from an earlier draft where a Table 1 has been renamed or dropped. As noted earlier in Q1, table 3 is poorly developed and should be revisited. How does one objectively measure compliance to MVCD distances? Use of LiDAR technology, laser rangefinders, etc. should be used and evidence of potential violations should be empirical and not based solely on subjective observations, even if they are performed by â€œqualified personnelâ€□. The technical document should include a glossary of all the acronyms used throughout the document as it has some excessive jargon and does not always read smoothly, especially compared to FAC-003-1. The use of explanation boxes is helpful.
Group
Bonneville Power Administration
Denise Koehn
Yes
This distance is reasonable in the table, but due to widely varying designs of structures it does not give a relationship of the outside wire to edge of ROW. It should be noted as outside wire, phase or conductor to edge of ROW. In addition, the effective date should allow transmission owners time to achieve this distance, perhaps one cycle.
Yes
Yes
Yes
Yes
Alternate version of R1/R2
VSLs proposed by the VM SDT
Yes
The basis of managing vegetation to MVCD in Table 2 (essentially withstand distances) will likely prove problematic. BPA believes NERC should develop an additional table that calls out minimum "buffers" based on attributes such as line voltage, line rating etc. This table should be a companion to Table 2. It is NERC's responsibility to regulate and we believe that they should do so. In this case, the loss of flexibility for the

owners is not necessarily a bad thing.
Group
Arizona Public Service Company
Jana Van Ness, Director Regulatory Compliance
No
These clearances could exceed the permitted ROWâ€™s on federal lands and the utility has no legal right to clear beyond those rights. In some cases the permitted ROW can exceed those distance and federal agencies could not allow you to clear beyond those clearances in this version.
Yes
No
Do not agree with real-time observation. Utility can use technology to determine all rated conditions if a tree related outage occurred.
No
Still lacks detailed information. SDT needs to specify the documentation it is left up to interpretation by the utility.
Yes
Neither version is acceptable ANSI-A300 part 7 should be included here. Having set distances will give federal agencies the ability to minimize a utilities TVMP.
VSLs proposed by NERC staff
Requires a higher degree of accountability as it should be.
Yes
Qualifications needs to be put back in the standard. There needs to be a clearance 1 requirement.
Group
Western Electricity Coordinating Council
Steve Rueckert
Yes
Yes
however the statement of acceptable forms of evidence implies that a dated attestation alone could provide evidence of compliance. An attestation alone would not represent sufficient evidence to support a conclusion of compliance with encroachment limits only of the absence of an outage.
Yes
Yes
annual vegetation management plans must have some flexibility. If the TO has the authority to create the plan they should have the authority to modify the plan. The key point is that changes, particularly delays to planned work would have to be approved. Do not believe â€œdecreases in fundingâ€☐ should be listed as a valid reason for modification of work plan related to a reliability standard. From an enforcement viewpoint, there is ambiguity or perceived ambiguity in â€œprovided they do not put the transmission system at risk of a vegetation encroachment.â€☐ Provided the potential that there may never be a self-report addressing this violation.
Draft 4 version of R1/R2
Draft 4 should be sufficient. If industry believes MVCD is not adequate then the tables for MVCD should be modified to account for sag and sway.

No
Individual
Bill Rees
BGE Forestry Management
Yes
No
Suggest including in â€œ4.4. Otherâ€☐ a phrase referencing government interference, such as â€œFederal, State or other regulatory interference, including legal or other legislative actions, that prevents performance to comply with this reliability standard.â€☐
No
M1 & M2 bullet: â€œReal-time observation of any MVCD encroachments.â€☐ implies that real-time observation of vegetation encroachment ensures reliable operation the Bulk Electric System. The reliability standard objective states; â€œTo improve the reliability of the electric Transmission system by preventing those vegetation related outages that could lead to Cascading.â€☐ However, real time observation of current operating conditions provides no assurance that vegetation will not lead to outages. BGE recommends removing the language. If an inspector finds vegetation encroaching into the MVCD during a visual inspection he / she should immediately initiate an Immediate Threat Notification. Therefore, this measure has no value.
Yes
Yes
Alternate version of R1/R2
BGE believes R1/R2 should contain language that ensures that vegetation is manage taking into account sag and sway throughout the conductors operating range as the alternate language above outlines. The six options proposed allows the Transmission Owner the flexability needed to manage the active ROW a varity of ways and at the same time ensures the reliable operation the Bulk Electric System with respect to vegetation.
VSLs proposed by the VM SDT
Yes
4.2.4 States that the Standard is not applicable to â€œâ€¦to Facilities â€¦. located inside the fenced area of a switchyard, station or substationâ€☐. This implies that anything within the fenced area of a switchyard, substation or power plant does not fall within the jurisdiction of FAC-003-2. Some fenced in areas could be very large and susceptible to vegetation encroachments issues. Suggest reference to â€œinside the fenceâ€☐ be removed. Disagree with R6. â€“ Inspection Frequency. Very prescriptive. Please consider allowing TOâ€™s to select an annual frequency that best fits their requirements, such as calendar year, every growing season, every non-growing season, etc. BGE currently defines their inspection frequency as annually during the non-growing season, October 1 to May 1. BGE believes inspecting during the dormant season is a best practice due to the ability of the inspector to identify vegetation defects, especially off the ROW, which could be hidden during the growing season due to foliage, canopy cover, etc. Also, if a utility elects to leverage an advance technology, such as LiDAR, it provides the most effective results when LiDAR is utilize during the growing season, therefore allowing the results of the advance technology to enhance the fall to spring inspection cycle. Table 1 â€“ Time Horizons, Violation Risk Factors, and Violation Severity Levels The VSLâ€™s for R7 all include â€œthe Transmission Owner failed

to completeâ€¦..% of its annual work plan (including modifications if any)â€☐. This is not clear to BGE. R7. allows plans to be modified due to changing conditions, for example ROW maintenance could be deferred to the following year due to mutual assistance agreements if the deferment does not violate the encroachment within the MVCD. The VSL implies this is a violation since the â€œmodificationâ€☐ deferred a certain percentage of the planned worked to the following year, therefore 100% of the planned worked wasnâ€™t completed. If the modification was excluded, than 100% of the planned work would have been completed.
Individual
Michael R. Lombardi
Northeast Utilities
No
The use of a minimum distance from the centerline of the circuit or structure is an incorrect measure to use for a set clearance distance of the active transmission right-of-way. Consideration should be given for the type of construction as different construction types (H-Frame, Lattice towers, Monopole delta or vertical construction) will require different widths of a cleared right-of-way to provide the necessary openings for these circuits. A minimum distance for 345-kV is now set at 150 feet based on the minimum distances from centerline. This may be correct for certain H-Frame and Lattice Tower configurations but it is excessive for monopole situations. A single pole configuration with vertically aligned conductors does not need this full 150 foot width. It is strongly recommended that a minimum distance from conductor be used in place of a set distance from centerline. As long as there is at least 30 - 40 feet of clearance in the right-of-way from the outermost conductors (adjusted to account for maximum sway at mid-span for longer spans), then this is the distance that should be used to develop the right-of-way widths. For example, a monopole structure with vertically aligned conductors would result in a cleared active right-of-way width of only 80 feet (40 feet from conductor to edge of cleared active right-of-way) using the minimum distances from the conductors. There is no need to extend this distance another 35 feet (on each side) in order to obtain the full 150 foot width. This requirement is excessive and must be adjusted to account for line construction variations. Instead of using the term "Centerline" as referenced on Table 3, the use of "outer phase" or "phase closest to tree line" would be more appropriate.
Yes
Yes
Yes
Yes
Alternate version of R1/R2
Option E above is preferred as it allows for variations based on differences in conductor heights, topography and other situations where a set height is not necessarily required in all instances and allows for the utility to determine the maximum heights of vegetation without performing detailed calculations of what the maximum heights must be along the various distances within each conductor span. If the utility is tasked with managing the vegetation to ensure no encroachments into the MVCD then it should be up to the individual utility how best to determine its management strategies that incorporate the determination of maximum vegetation heights in each section on its system.
VSLs proposed by the VM SDT

No
Group
Tampa Electric Company
Luke Diruzza
No
We have concern with the â€œMinimum Distancesâ€☐ as listed in Table 3. What analytical methodology, criteria and rationale was utilized to determine each recommended distance? In addition, we have concerns regarding the change to a pre-determined distance. This seems to be a major shift from the vegetation to conductor methodology employed previously and throughout this standard? NERC/FERC must recognize that while protecting and securing grid reliability, each utility must also balance the environmental, political, customer and economic issues and impacts which will occur with the implementation of the Table 3 clearances. We question whether this is the most responsible action to take given the current state of the economy as well as the environmental and political sensitivity impacts which will result. Tampa Electric questions whether Table 3 will improve System reliability. Since the inception of standard FAC-003-1 Tampa Electric has not had a Category 1 or Category 2 outage on our 230kV Transmission System. We donâ€™t believe that the changes proposed to table 3 will improve overall service reliability. It is Tampa Electricâ€™s opinion that each utility should define the width of its own Active Transmission line ROW. However, if such a table is to be utilized, Tampa Electric recommends the following changes or adjustments to Table 3. 1. Expand the table to account for the various types of Transmission construction; i.e. vertical versus horizontal conductor configurations. 2. Use a distance from the outermost conductor, not the centerline. This will account for construction type and better achieve a consistent clearance from conductors. 3. We recommend reducing the distances in Table 3 by 12.5 feet for each voltage category. 4. Specify whether the voltage is based upon the design or operating voltage. 5. Reformat the voltage ranges to 100kV - 200kV, 200kV â€“ 300kV, 300kV â€“ 400kV, etc. as an example; this would create a more appropriate range of voltages and clearance distances. The reformatted voltage ranges eliminate confusion. For example, under the current proposal it is unclear in which category a nominal 230kV line should be since sometimes such a line can operate at up to 232kV during low-load conditions.
Yes
These changes add improved clarity and defintion to this section.
Yes
These changes allow for qualified review of field findings.
Yes
This better clarifies section R3
Yes
These changes add greater clarity, as well as real world examples, to this standard.
Draft 4 version of R1/R2
Quite frankly, the alternatives listed above, or for that matter any other vegetation managment options, should be establised by the utility. The goals in R1 & R2 are very clear. The alternatives listed above will create a double or triple standard of vegetation clearance for each different type of Transmission construction.
VSLs proposed by the VM SDT
Tampa Electric agrees with the SDT statement â€¦ â€œFor example, not all encroachments lead to Sustained Outages.â€☐ As such, we agree, a lower level of VSL is appropriate. Tampa Electric also agrees with this statement â€œ Moreover, there is an operational differentiation between a fall-in, blow-together or grow-in event. â€œ Recommend the team

examine the analytical rational for the following statements so as to better explain and clarify this issue to NERC. â€œA fall-in has never been known to cause a cascading outage. Therefore the team feels that a Lower VSL is appropriate. A blowing-together-caused fault is somewhat more egregious than a fall-in, as it has the potential for re-occurring and is therefore assigned a Higher VSL.â€☐
No
No additional comments
Group
Corporate Compliance
Silvia Parada Mitchell
No
Although there is support for making Active Transmission Line Right of Way a clearly defined term, and the foundation for compliance with FAC-003-2, the distances in the table are arbitrary and are not supported by any scientific or engineering analysis. It is possible that such a table could be interpreted to define the minimum width of future lines. Different construction configurations require different ROW widths.
Yes
No
The measure is adding to the requirement. The measure should define how a requirement is met and not interpret or add to the requirement, otherwise this will add to confusion, instead of clarity, which should be the goal of any revised reliability Standard. Also, the measure implies that a fault investigation must be done. As written, momentary outages are included, and a fault investigation should not be required for momentary outage. It also places the same weight of violation on a momentary outage as it does a Sustained outage, which appears on its face not to appropriate nor necessary to meet the goal of FAC-003-2. In addition, an outage investigation is not a finite process that produces identical homogenous results every time. Of particular concern is the possibility that should a Transmission Owner have one or more momentary outages and not find the cause, then later have another outage (Sustained or Momentary), such a finding appears to lead to a multiple violation. This is inconsistent with focusing requirements on reliability risks to the bulk electric system.
Yes
Yes
Draft 4 version of R1/R2
The alternative is a fill in the blanks requirement.
VSLs proposed by NERC staff
Again the drafting team is trying to control the terms of a requirement by using the compliance elements. FPL agrees there is a direct link between vegetation growing in to conductors from below has a direct correlation to cascading events and fall-in and blow-in outages are no more incidental than a cross arm failure to a cascading event. These components should be handled in the requirements and not in the compliance element.
Yes
R5 as written is vague. It leads to confusion in interpretation. FPL recommends the following wording. R5. The Transmission Owner shall certify each corridor or line section that it meets the standards it set forth under R3 until the next planned management cycle when it is completed. If a location in known to not meet the criteria defined under R3, a mitigation plan must be in place to prevent a violation of R1 or R2. R1 and R2 are too inclusive. They equate vegetation growing in to conductors from below the same as vegetation falling or blowing into the conductors

from within the Active ROW. There is no evidence that a cascading event has ever been caused by the latter two events. This standard should concentrate on vegetation growing from below the conductor. Suggested wording of R1 and R2 is as follows. R1. Each Transmission Owner shall manage vegetation to prevent encroachment into the Minimum Vegetation Clearance Distance (MVCD) as shown in Table 2 from within the active ROW on of any line identified as an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions). Encroachments are determined by: 1. An encroachment, observed in real time, 4. An encroachment due to a grow-in from below the conductor in the active ROW that caused a Fault. R1. Each Transmission Owner shall manage vegetation to prevent encroachment into the Minimum Vegetation Clearance Distance (MVCD) as shown in Table 2 from within the active ROW on of any line that is not an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions). Encroachments are determined by: 1. An encroachment, observed in real time, 4. An encroachment due to a grow-in from below the conductor in the active ROW that caused a Fault.
Individual
Bryan Taylor
Idaho Power
Yes
I support the description for the active right of way. However, I believe there needs to be a provision that addresses identifying potential hazards outside the active right of ways that may pose a risk to the transmission lines.
Yes
This will allow the utilities to address conditions that are within their control.
Yes
Yes
Yes
Alternate version of R1/R2
Alternative R1/R2 allows the utility to maintain adequate clearances with their preferred approach.
VSLs proposed by NERC staff
Seems like there should be a lesser severity level for violations for R3-R7.
Yes
I'd like to see language or NERC support to encourage federal agencies to expedite vegetation management maintenance requests and minimize the barriers to perform work on federal lands.
Individual
Anne Beard
PNM
No
ROW easements vary according to land ownership therefore, potentially subjecting the utility to be liable for land outside of easement/ROW.
Yes
No
Needs a definition of Real Time Observations

Yes
Yes
Alternate version of R1/R2
VSLs proposed by the VM SDT
The expectation is for perfection or zero encroachments at all times. It would be cost prohibitive to maintain the system under those rules. PNM recommends the VM SDT VSLâ€™s.
No
Individual
James Sharpe
South Carolina and Gas
Yes
Yes
Yes
Yes
Yes
VSLs proposed by the VM SDT
No
Group
Southern Company Transmission
JT Wood
No
Depending on the intent this may create a problem. We are concerned the addition of Table 3 could be interpreted to mean something completely different than what we believe to be its intention. Please consider alternate wording to Footnote 2: A strip or corridor of land that is occupied by active transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities. However, the active transmission line ROW cleared width it is not to be less than the width of the easement itself unless the easement exceeds distances as shown in Table 3 for various voltage classes. If the SDT determines keeping Table 3 is the appropriate course of action, we recommend clarifying its intent better; either in a footnote or in the title. Adding a footnote stating the Table is not applicable if the distance from the center line of the conductor to the right-of-way edge is less than the appropriate distance indicated in the table. Another option might be to add a statement to the title such as, â€œIf the distance from the centerline of the circuit to the edge of the easement is less than the values in Table 3, that distance is considered active ROWâ€☐.
Yes
Yes

Yes
While voting yes we are concerned about the interpretation of the expanded verbiage, how much documentation will be enough.
No
The first sentence of the Requirement 7 Rationale conflicts with the second sentence. The R7 Rationale should be reworded as follows: "This requirement sets the expectation that the work identified in the annual work plan should be completed as planned. However, an annual vegetation work plan must allow for work to be modified in response to changing conditions. These modifications must take into consideration the anticipated growth of vegetation and all other environmental factors, provided that the changes do not cause a vegetation encroachment within the MVCD."
Draft 4 version of R1/R2
We feel the alternative language is too confusing. Does a utility choose one option from the list and expect it to cover all situations, or can the utility pick one option from the list and apply that option to one span, and then another option for the next span. The proposed alternate verbiage makes no distinction as to when options can or cannot be utilized. The language in Draft 4 seems to cover the various scenarios a utility will face in its vegetation management program while giving the utility the flexibility necessary to address these situations in an appropriate manner.
VSLs proposed by the VM SDT
We support the SDT version of the VSLs. The version proposed by staff does not recognize the objective of FAC-003-2 which clearly states, â€œTo improve the reliability of the electric Transmission system by preventing those outages that could lead to Cascading.â€☐ If a fall-in occurs in an afternoon thunder storm and investigation reveals the tree was on the right-of-way by one or two feet, staffs VSLs would treat this outage with the same severity as an outage where a fully loaded line in a heat wave sagged into unmaintained brush growing directly beneath the conductor. The first case would rarely, if ever, lead to cascading. The second case could easily lead to cascading. Staffâ€™s VSLs seem to indicate a desire to â€œgold plateâ€™ the system to insure 100% reliability, which will never be achieved absent of unlimited resources and with total disregard to cost.
Yes
The NERC Glossary of Terms provides a definition for Flashover. The Rationale boxes for R1 and R2 use the term â€œspark-overâ€☐. This is inconsistent with other references in the Standard. Note that the term Flashover is used in footnote No.4. Please resolve the inconsistency between these terms. We are concerned FAC-003-2 is being developed under a zero tolerance philosophy, while other NERC standards do not adopt a zero tolerance philosophy. Industry performance under FAC-003-1 indicates the standard is working and that industry is responding to ensure reliability of the electric Transmission system. We would like to thank the SDT for the work they have put into developing the proposed draft.
Individual
Greg Rowland
Duke Energy
Yes
However, due to different design attributes of transmission lines, it may be better to change the distance in Table 3 from a centerline distance to a â€œMinimum Full Active Transmission Line ROW Width Distanceâ€☐.
Yes
No
The last sentence of this modification could be misinterpreted by a compliance representative to imply that all Faults must be investigated to eliminate or confirm vegetation as the cause of the fault. There are several

sources (e.g. lightning, wind-blown debris) of Faults and several appropriate operational responses, some of which may not include field investigations, depending on the circumstances surrounding each Fault. Thus, the current wording is gray and should be modified to aid industryâ€™s understanding and thus to ensure compliance. The interpretation we suggest may not be obvious, but our experience with previous interpretations of certain facets of FAC-003-01 would indicate the need to better define the expectation. A potential modification to the last sentence of M1/M2 could be: If a later confirmation of a Fault by a qualified person shows that a vegetation encroachment within the MVCD has occurred, this shall be considered the equivalent of a Real-time observation.
Yes
Yes
Draft 4 version of R1/R2
VSLs proposed by the VM SDT
No
Individual
Andrew Z.Pusztai
American Transmission Company
Yes
Yes
Yes
Yes
Yes
Draft 4 version of R1/R2
ATC feels that Draft 4 Version of R1/R2 is the preferred version. The Alternate version is too prescriptive and has little flexability.
VSLs proposed by the VM SDT
ATC believes the VSLs proposed by the VM SDT best supports the NERCâ€™s VSL Criteria. The NERC Staff VSLs do not allow for Lower or Moderate VSLs which recognizes significant value as nearly meeting the intent of the requirement. Furthermore, it does not allow for encroachment where absent a sustained outage. Every encroachment in real time would not go directly to a â€œHighâ€☐ VSL where performance has limited value.
Yes
1.) Rationale boxes associated with R1, R2 and R3 within the standard include reference Tables and Figures in the â€œGuidelines and Technical Basisâ€☐ without specifying where they are located. ATC recommends inserting this information as applicable. 2.) ATC raises a previous draft concern on including Rationale Boxes plus Guidelines and Technical Basis as part of the NERC Reliability Standard. ATC recommends that the SDT either remove these sections or make them separate from the formal standard to eliminate any risk that these may be construed as requirements. An alternative method is to very clearly identify which parts

of the standard are subject to compliance and considered mandatory and which are not considered requirements and are only for guidance in meeting the requirements. 3.) ATC believes the Measurements are well written and provide guidance on acceptable compliance evidence related to the requirement. 4.) Measurement M2 related to R2 states that outages related to encroachments have records confirming no Real-Time observations of any MVCD encroachments. ATC feels this would be hard to prove as a negative. It could require one to show every single patrol or inspection has documentation stating no real time encroachments were observed. 5.) Editorial Comment on Draft SDT VSLs for R2: To clarify the statements made for the Moderate, High and Severe VSLs. please add the verbiage, â€œinto the MVCDâ€☐ after â€œThe TO had an encroachmentâ€¦â€¦.â€☐
Group
Hydro One
Sasa Maljukan
No
A DC table for Table 3 similar to the MVCD table should be added. There should be a statement in Table 3 that is consistent with footnote number 2 stating that the minimum width of the Active Transmission Line ROW is either the full width of the easement or, if the easement is wider than the distances in Table 3, the minimum distances must not be less than the distances shown in the Table. The use of a minimum distance from the centerline of the circuit or structure is an incorrect measure to use for a set clearance distance of the active transmission right-of-way. The description does not take into account vertical versus horizontal design configuration. Consideration should be given for the type of construction as different construction types (H-Frame, Lat-tice towers, Monopole delta or vertical construction) will require different widths of a cleared right-of-way to provide the necessary openings for these circuits. A minimum distance for 345-kV is now set at 150 feet based on the minimum distances from centerline. This may be correct for certain H-Frame and Lattice Tower configurations but it is excessive for monopole situations. A single pole configuration with vertically aligned conductors does not need this full 150 foot width. It is strongly recommended that a minimum distance from conductor be used in place of a set distance from centerline. As long as there is at least 30 - 40 feet of clearance in the right-of-way from the outermost conductors (adjusted to account for maximum sway at mid-span for longer spans), then this is the distance that should be used to develop the right-of-way widths. For example, a monopole structure with vertically aligned conductors would result in a cleared active right-of-way width of only 80 feet (40 feet from conductor to edge of cleared active right-of-way) using the minimum distances from the conductors. There is no need to extend this distance another 35 feet (on each side) in order to obtain the full 150 foot width. This requirement is excessive and must be adjusted to account for line construction variations. Instead of using the term "Centerline" as referenced on Table 3, the use of "outer phase" or "phase closest to tree line" would be more appropriate. There is published literature using the term â€œcleared widthâ€☐ to indicate the distance from the outer phase to the tree line. This distance should be used in the Active ROW definition. The word easement is also used in the definition. Is there a reason the Active ROW only includes easements, not fee ownership, license or some other right to occupy and manage the ROW? Would Active ROW include â€œdanger tree rightsâ€☐ on land? These questions need to be addressed in the standard (in text) and technical reference document (in graphics).
Yes
No
A clarification for M1 is needed regarding whether entities will have to attest to the fact that there has never been an encroachment in the MVCD.

Yes
Yes
Alternate version of R1/R2
Alternate Version E would allow a Transmission Owner to use an approach consistent with the current version of FAC-003 by defining a minimum clearance distance and a vegetation management clearance distance. This approach has met the objectives of FAC-003 since 2006. Use of version E would change the standard from a prescriptive approach to a Transmission Owner defined approach. In addition, Alternate Version E is preferred as it allows for variations based on differences in conductor heights, topography and other situations where a set height is not necessarily required in all instances and allows for the utility to determine the maximum heights of vegetation without performing detailed calculations of what the maximum heights must be along the various distances within each conductor span. If the utility is tasked with managing the vegetation to ensure no encroachments into the MVCD then it should be up to the individual utility how best to determine its management strategies that incorporate the determination of maximum vegetation heights in each section on its system.
VSLs proposed by the VM SDT
The wording in the VM STD VSLs should be modified to include whether or not the TO managed any vegetation on that particular line. A more severe VSL should be assigned to any encroachment or sustained outage that was caused as a result of a TO not performing any vegetation management activities on that line. For example, if vegetation management activities were completed on 80% or 90% of the line and additional work was in progress on the remainder of the line, but an encroachment or sustained outage occurred on the spans that were scheduled to be done as part of the annual plan, the TO should be held accountable for this but at a lower severity level.
Yes
Hydro One wants to thank the SDT for the effort that has gone into developing this proposed revision to FAC-003. Overall the new version is consistent with FERC Order 693 and will be a straightforward, workable, and auditable standard. One item requiring clarification and change is the Active ROW definition. The recent addition of a centerline distance to edge of Active ROW is not acceptable. In many areas design standards allow a smaller ROW width with no compromise to â€œcleared widthâ€☐ or tree related reliability of the line. The SDT needs to address this issue. In R5, the phrase 'where a transmission line is put at potential risk due to the constraint' should be better defined. This is vague and could lead to inconsistent practices between utilities. All undesirable species on the full width of the ROW are defined as 'potential risks to the transmission line' regardless of height or location at the time of vegetation management. Interim corrective action should only be required when the potential risk is approaching the imminent threat classification.
Individual
Terry Harbour
MidAmerican Energy
Yes
Yes
No
Examples should be moved to the rationale boxes to avoid confusion on what is required and what is an example. All rationale boxes should have a disclaimer to the effect saying "For guidance only, not for enforcement".

No
MidAmerican supports the additional detail the R3 should end after the first sentence. The additional detail should be moved to the rationale box as additional guidance.
No
MidAmerican supports the additional detail. However R7 should end after the first sentence. All additional material should be moved to the rationale box.
Draft 4 version of R1/R2
VSLs proposed by the VM SDT
Yes
Any references to "observed in real time" should be removed. Vegetation contacts must be verified and references to real time are inappropriate. This causes difficulties in proving a negative in real time.
Group
Pepco Holdings, Inc - Affiliates
Richard Kafka
Yes
Yes
Yes
Yes
Yes
Draft 4 version of R1/R2
Neither set is correct. The SDT proposed VSLs do not identify encroachment into the MVCD of a line not in an IROL or Major WECC transfer path, and the NERC Staff proposed VSLs do not do not identify encroachment into the MVCD of a line that is in an IROL or Major WECC transfer path
No
Group
MROâ€™s NERC Standards Review Subcommittee (nsrs)
Joseph DePoorter
Yes
The NSRS agrees in whole to the question but has the SDT taken into consideration the difference in ROW may be different in Urban and Rural settings?
Yes
The NSRS believes that the new definition provides greater clarity with respect what does not constitute a compliance violation versus the previous version.
Yes
No
The NSRS does not believe that the new specificity that has been added to R3 will improve the reliability of the BES. It is our opinion that the requirement would have been clearer if it had ended after the first

sentence. The additional language after the first sentence does not improve clarity. The whole (as written) requirement may be interpreted as a requirement for â€œeach spanâ€ of Transmission line that the Requirement will be applied to. In measures for other requirements the SDT has done a very good job of stating and clarifying (in their opinion) what acceptable forms of evidence are. M3 would benefit from this type of clarification.
Yes
The NSRS has issue with the word â€œmayâ€ (and its components along with the associated bulleted points) and recommends that it is removed and placed in the rational box.
Draft 4 version of R1/R2
It is the NSRSâ€™s opinion that that the requirement as currently written in version 4 is consistent with the intent of a standard; i.e. stating what is required as opposed to stating how to achieve what is required.
VSLs proposed by the VM SDT
Yes
1.) The NSRS notices that a previous draft concern on including Rationale Boxes plus Guidelines and Technical Basis as part of the NERC Reliability Standard. The NSRS recommends that the SDT either remove these sections or make them separate from the formal standard to eliminate any risk that these may be construed as requirements. An alternative method is to very clearly identify which parts of the standard are subject to compliance and considered mandatory and which are not considered requirements and are only for guidance in meeting the requirements. Such as; State within in the text that this information â€œIs not subject to enforcementâ€. 2.) The NSRS believes the Measurements are well written and provide guidance on acceptable compliance evidence related to the requirement. 3.) Measurement M2 related to R2 states that outages related to encroachments have records confirming no Real-Time observations of any MVCD encroachments. The NSRS feels this would be hard to prove as a negative. It could require one to show every single patrol or inspection has documentation stating no real time encroachments were observed. 4.) Editorial Comment on Draft SDT VSLs for R2: To clarify the statements made for the Moderate, High and Severe VSLs. please add the verbiage, â€œinto the MVCDâ€ after â€œThe TO had an encroachmentâ€¦â€¦.â€
Individual
Claudiu Cadar
GDS Associates
Yes
- ROW abbreviation comes prior to the full term (marked footnote prior to the full term as stated in 5. Background). Please make correction accordingly.
Yes
No
- Need to specify who qualifies as â€œqualified personnelâ€ to observe the vegetation condition.
No
- We suggest to eliminate / change the word â€œdynamicsâ€ because can create confusion with regards to the extent of documentation that has to be prepared. - Requirement should clearly state the criteria as in the maximum design (rating) or maximum operating conditions
Alternate version of R1/R2
- E) seem more appropriate. The alternate R1/R2 standard requirements

shall reduce the number of possibilities and simplify the criteria towards the design / operating conditions and additional standards ought to be considered in concert with current standard.
Criteria will be probably best represented by a mix of the two VSLs as follows: - Keep the Lower and Moderate VSLs from SDT with both absent Sustained Outage. Add the fall-in as specific encroachment to the Lower VSL and grow-in as specific encroachment to the Moderate VSL - Keep the High / Severe VSLs from NERC
Yes
- Effective Dates. Clarify effective dates in paragraphs 2 and 3. This should only be applicable to Canada as Standard are not mandatory and enforceable in the US unless further approved by FERC. - Exceptions. Regional Differences must be approved just like NERC Standards, further explanation is required of these exceptions to garner a better understanding of the intent - Background. The paragraph exemplifying as a localized customer service may get disrupted if vegetation will make contact with a 69kV line is not appropriate for the standard while it is given that this applies to the BES 200kV and above. - Requirement R2. The paragraph â€œ[â€¦] Sustained Outage of applicable lines that are not elements [â€¦]â€☐ should state the voltage threshold of 200kV and above - Requirement R4. Who qualifies as â€œqualified personnelâ€☐ to observe the vegetation condition? Need clarification. - Requirement R5. Rationale. Corrective action guidance should be provided within the Requirement. Set the examples for the Guidelines section. - Guidelines and Technical Basis. oRequirement R1 and R2. The example meant to prove the point of â€œline conductor intentionally or inadvertently operated beyond its ratingâ€☐ is contradicting the guideline. The emergency actions should not violate any standards and should not cause an outage. If such thing happens, the vegetation related outages should be in violation of the requirements. oRequirement R3. How is every possible combination of wind speed, loading and conductor properties going to be addressed? Should a national standard be referenced as a minimum requirement? More guidance should be provided. oRequirement R5. Wouldn't a violation have occurred with the encroachment of the vegetation per R2? The potential to put the transmission system at risk is not well defined and could be interpreted as encroachment into the area defined by the appropriate table(s). Need clarification. oRequirement R7. Regarding the statement â€œIt is only intended to require that the Transmission Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCDâ€☐ if no identifier is utilized how will compliance be gauged? By encroachment? By outage? Need clarification. oRequirement R7. Regarding the evidence of annual work plan execution, when would the change in plan need to be documented? Has this moved away from requiring the documentation of plan change at the time of occurrence? Need clarification.
Individual
Joe Knight
Great River Energy
Yes
Yes
GRE believes that the new definition provides greater clarity with respect what does not constitute a compliance violation versus the previous version.
Yes
GRE agrees with the revisions made to this standard since the last posting and requests clarification on what constitutes a qualified person.
No

GRE does not believe that the new specificity that has been added to R3 will improve the reliability of the BES. It is our opinion that the requirement would have been clearer if it had ended after the first sentence. The additional language after the first sentence does not improve clarity. In measures for other requirements the SDT has done a very good job of stating and clarifying (in their opinion) what acceptable forms of evidence are. M3 would benefit from this type of clarification.
Yes
Draft 4 version of R1/R2
VSLs proposed by the VM SDT
GRE prefers the Drafting Teamâ€™s VSLs over the VSLs written by the NERC staff. The VSLs that were written by the SDT appear to be clearer and less subjective as opposed to the VSLs that were written by NERC staff. The VSLs written by the NERC staff came across as being less clear and more subjective.
Individual
Kirit Shah
Ameren
No
Does this mean wider ROW easements will need to be acquired to be compliant or will this apply to ROWâ€™s for new circuits going forward?
Yes
Yes
Yes
No
Funding Adjustments (increase or decrease) â€“ need more description to imply only when planned vegetation work is â€œover and aboveâ€□.
Draft 4 version of R1/R2
VSLs proposed by the VM SDT
Yes
Funding Adjustments (increase or decrease) â€“ need more description to imply only when planned vegetation work is â€œover and aboveâ€□.
Individual
Earl V. Burnside
PPL Electric Utilities
No
Centerline (CL) distances shown in Table 3 are shown as Minimal distances from CL. If utility is not able to define its ultimate ROW, due to CL agreement or other circumstances, these minimal distances may not be applicable and as such could result in non-compliance as written.
Yes
No
As written M1 requires evaluation of condition by â€œqualified personâ€□ but no definition of qualified person given. Should be more direct and point to physical evidence of vegetation encroachment into MVCD, i.e. burned vegetation.

No
As written, R3 now requires documentation of conductor dynamics as related to ratings and rated operational conditions. Not clear how this information is to be presented and documented and how vegetation conditions that exist are to be documented to provide evidence that management processes and procedures are adequate to prevent encroachment into MCVD.
Yes
Alternate version of R1/R2
Alternate C provides assurances that growth rates, maintenance cycle, and max-sag are taken into consideration.
VSLs proposed by the VM SDT
No
Individual
Jianmei Chai
Consumers Energy Company
No
Table 3 does not adequately address ROW width requirements based on the type of construction used for structures, especially for the two lower voltage classes, 69-138kV and 139-230 kV. Lines constructed on H-Frame structures have a much wider footprint across the ROW than do single pole construction and most steel tower construction types. The minimum ROW width listed in Table 3 for a 138 kV line constructed on a wooden H-Frame may put the outside conductor within MVCD under windy conditions due to wind displacement of conductors and trees. Consumers Energy recommends that Table 3 be modified to describe the minimum distance in the table is the vertical plane of the outside conductor to the edge of the active transmission ROW and therefore independent of the width of the structure construction type.
Yes
No
None of the three examples of acceptable forms of evidence provided in the revision prove that a Transmission Owner actively managed vegetation to prevent encroachment into the MVCD. The Measure should require proof of active ROW clearing activity per the transmission vegetation management plan, such as invoicing or crew field reports or vegetation inspection data from the annual vegetation inspection.
No
This really is another attempt at avoiding defining a minimum clearance specification and is not practical. As written, this would require each Transmission Owner to define and document the procedures, processes or specification by individual span for every line owned or operated by the Transmission Owner. Each span varies in length and profile and a single line may have several different conductor types with different load ratings. Line loadings will vary along the line based on substation taps, etc. The dynamics described in the language could only be done on an individual span basis to be reasonably accurate. This is not practical from a planning standpoint or from a standpoint of implementing clearing work in the field.
Yes
Alternate version of R1/R2
Prefer Alternative A
VSLs proposed by NERC staff

No
Group
Tri-State Generation & Transmission
Linwood Blacksmith
Yes
Table 3 should be referenced as a guideline only.
Yes
Yes
Yes
Yes
Draft 4 version of R1/R2
VSLs proposed by the VM SDT
No
Individual
Michael Pakeltis
CenterPoint Energy
No
There is no rationale provided for the â€œminimum distancesâ€☐ stated in Table 3, and they far exceed the ROW widths that CenterPoint Energy owns (typical total 100â€™ ROW width for 2-ckt 345kV line) for its current 345kV system, and as such, are open for misapplication and misinterpretation as an intended minimum standard for making a fall-in determination for R1 and R2 outside the legal limits of the utility. Table 3 should be deleted. If kept, there should be sufficient rationale included within the Guidelines and Technical Basis to explain how it was derived and how it is to be used within the Standard. CenterPoint Energy agrees with the removal of â€œactive transmission line ROWâ€☐ as a defined term; however, the footnote should be deleted as well since it attempts to create a definition which is not accurate, necessary or useful. Throughout the Standard, the phrase â€œactive transmission line ROWâ€☐ should be replaced with â€œtransmission line ROWâ€☐ to eliminate the qualifying term â€œactiveâ€☐. In making a fall-in determination for R1 and R2, the limit should be â€œwithin the full extent of the Transmission Ownerâ€™s transmission ROW as defined by easement, fee simple, or other legal rightsâ€☐ as discussed in the Guidelines and Technical Basis regarding the vegetation management maintenance approach. This places the determination of the width of the ROW for determination of fall-in violations clearly on the Transmission Owner and the within the limits of its legal rights to control the vegetation that has fallen into the line under R1 and R2.
Yes
No preference.
No
CenterPoint Energy does not believe a performance based requirement should require evidence of processes and procedures to demonstrate compliance. However, if the majority of industry commenters agree with the SDTâ€™s approach, CenterPoint Energy has several concerns.

Assuming R1.1 and R2.1 regarding observations of encroachments are not deleted from the Standard, then only the first paragraph regarding forms of evidence is helpful and necessary. The second paragraph is not relevant or necessary. The special qualification of Sustained Outage should be contained in R1 and R2, not M1 and M2. Also, the reference to a â€œFaultâ€□ in M1 and M2 instead of a â€œSustained Outageâ€□ changes the scope of what is specified in R1 and R2 which is not reasonable. A â€œFaultâ€□ can be associated with a Momentary Outage or a Sustained Outage. The scope of R1 and R2 is specific to Sustained Outages.
No
See response to Q3 above. However, assuming R3 is not revised to exclude processes and procedures, we have no preference to the wording between the two drafts.
No
See response to Q3 above. However, assuming R7 is not revised to exclude processes and procedures, the new wording is preferred since it is more specific. Additionally, a new ambiguous phrase is introduced, â€œprovided they do not put the transmission system at risk of a vegetation encroachmentâ€□, which we recommend to be changed to more specific wording, â€œprovided they do not allow encroachment of vegetation into the MVCDâ€□.
Draft 4 version of R1/R2
CenterPoint Energy does not believe a performance based requirement should be this prescriptive. However, if the majority of industry commenters agree with the SDTâ€™s approach, CenterPoint Energy has several concerns. The terminology, â€œoperating within Rating and Rated Electrical Operating Conditionsâ€□ is sufficiently definitive. There is no need to be more prescriptive. Alternate R1/R2 (E) is already similar to the Draft 4 wording. Of the two alternative, we recommend keeping the Draft 4 wording as is; however, we recommend moving the applicability of transmission line ratings to the Applicability section of the Standard as â€œ4.5 Other: The Standard does not apply to any occurrence, non-occurrence, or other set of circumstances that are beyond the Rating and Rated Electrical Operating Conditions of the Facilities defined in 4.2.â€□ These conditions should be applicable to all elements and requirements of the Standard just as the force majeure statement does.
Neither. However, we recommend that High or Severe violations be based only on Sustained Outages experienced and the reliability importance of the transmission line. Any process or procedure based requirement, if kept within the Standard, should have a Lower or Moderate designation based on the utilities intent or capability to comply with the Requirement.
Yes
1. CenterPoint Energy believes the proposed FAC-003-2 is not a performance-based standard, despite being labeled as such, because it remains too focused on processes and procedures. CenterPoint Energy fails to see much difference in the approach from the current Standard. CenterPoint Energy believes a performance based requirement would provide performance criteria that an entity would be measured against. An example of a performance based requirement would be the following: R1. â€œEach Transmission Owner shall manage vegetation to prevent encroachment that results in no more than one (1) Sustained Outage per XXX circuit miles of applicable lines within any twelve (12) month period.â€□ M1. Each Transmission Owner has evidence that it had in no more than one (1) Sustained Outage per XXX circuit miles of applicable lines within any twelve (12) month period. Examples of acceptable forms of evidence may include dated reports of vegetation-related Sustained Outages or dated attestations as to no vegetation-related Sustained Outages have occurred. However, if the majority of industry commenters agree with the SDTâ€™s approach, CenterPoint Energy has the following additional concerns: 2. The phrases â€œactive transmission line ROWâ€□

and â€œActive Transmission Line ROWâ€☐ are no longer considered defined terms and should be deleted from the Standard along with footnote 2, the Compliance Section for Periodic Data Submittal as well as the Guidelines and Technical Basis. As found throughout the Standard, the phrase should be replaced with the common terms utilized in the Guidelines and Technical Basis section, â€œTransmission Ownerâ€™s transmission ROW as defined by easement, fee simple, or other legal rightsâ€☐. 3. In the Background section fall-ins are characterized as â€œstatistically intermittentâ€☐ and â€œthese types of events are highly unlikely to cause large-scale grid failuresâ€☐. We agree and therefore recommend that fall-ins be excluded from the Requirements R1, R2, and Periodic Data Submittal of outages. 4. R4 should be deleted. R4 is related to processes and procedures and should be combined into R3. The result of not following the notification process or procedure is that a Sustained Outage may occur that would be captured by M1 and M2. The process and procedure would be measured by M3. 5. R5 and M5 contain the ambiguous phrase, â€œwhere a transmission line is put at risk due to the constraintâ€☐. This phrase should be replaced with the more specific terminology in R1 and R2 as, â€œwhere a transmission line cannot perform within its Rating and Rated Electrical Operating Conditions due to the constraintâ€☐ or as in R3 as â€œwhere a transmission line will be subjected to an encroachment into the MVCD due to the constraintâ€☐. 6. For R6, the detailed rationale and studies used for the determination of the required one year inspection cycle should be included in the Guidelines and Technical Basis. The explanation provided in the Rationale that it is â€œbased upon average growth rates across North America and on common utility practiceâ€☐ are unfounded and arbitrary without a specific reference to a North American study. 7. R7 contains the ambiguous phrase, â€œprovided they do not put the transmission system at risk of a vegetation encroachmentâ€☐. This phrase should be replaced with the more specific terminology in the Rationale for R7 and Requirement R3 as â€œprovided they do not allow encroachment of vegetation into the MVCD.â€☐ 8. Just as the force majeure statement was moved to the Applicability section of the Standard, the exception for applicability beyond the Rating and Rated Electrical Operating Conditions should be included in the Applicability section as well. Currently, it is only included in R1, R2, and R3. It should be made clear that the other Requirements and Measurements ARE NOT applicable in situations beyond the Rating and Rated Electrical Operating Conditions. This is already discussed in the Guidelines and Technical Basis but not evident within the Standard. 9. The Periodic Data Submittal should be clarified to as to the specific conditions under which Sustained Outages are reported. The Applicability section includes the force majeure; however, other exclusions are not so evident. We recommend the wording be changed to include all applicable exclusions for added clarity. We recommend the following wording: â€œThe Transmission Owner will submit a quarterly report to its Regional Entity, or Regional Entityâ€™s designee, identifying the Sustained Outages caused by vegetation, as defined in the categories below, of transmission lines operating within Rating and Rated Operating Conditions as determined by the Transmission Owner, exclusive of the force majeure conditions in Section 4.4, that include, as a minimum, the following.â€☐ Also, the within the Categories listed, the phrases â€œactive transmission line ROWâ€☐ should be deleted and replaced with â€œTransmission Ownerâ€™s transmission ROW as defined by easement, fee simple, or other legal rightsâ€☐. This places the determination of the width of the ROW for determination of fall-in violations clearly on the Transmission Owner and the within the limits of its legal rights to control the vegetation that has fallen into the line under R1 and R2 causing the submittal of a reportable sustained outage. 10. The Guidelines and Technical Basis and the Technical Reference with the Gallet Equation should be combined into one document as a supplement to the Standard to avoid duplication in wording and misinterpretation of context. 11. We agree that the Rationale

test boxes should be deleted from the Standard and applicable explanatory text be included within the Guidelines and Technical Basis. 12. The Guidelines and Technical Basis should include the background and basis for 4.2.4 that excludes the Standard from applying to fenced substations. 13. The Guidelines and Technical Basis should contain more specific examples of violations of the Requirements and highlight specific exceptions related to vegetation related outages, especially fall-ins and force majeure exclusions. 14. The language in R6 refers to inspecting â€œtransmission linesâ€☐ and Table 1 for R6 refers to inspecting â€œROWâ€☐. Both areas should use consistent terminology. 15. In the Guidelines and Technical Basis section for R6, the reference to the VSL calculation units and the example units should be consistentâ€"the example should use â€œcircuit milesâ€☐, not just â€œmilesâ€☐. 16. In general, the proposed FAC-003-2 has gone FAR beyond what was contemplated by the Commission in FERC Order 693 and equates to a total re-writing of the Standard for no apparent reason. The Commission's determination dealt with the following areas: (1) applicability; (2) inspection cycles; and (3) minimum clearances on National Forest Service lands. For instance in Paragraph 729, the Commission states, â€œAs proposed in the NOPR, the Commission approves Reliability Standard FAC-003-1 with no proposed modification on the issue of clearances. The Commission reaffirms its interpretation that FAC-003-1 requires sufficient clearances to prevent outages due to vegetation management practices under all applicable conditionsâ€¦.â€☐ Rewriting the minimum clearances introduced a new set of confusing definitions, and further burdens the Transmission Owners with new documentation requirements with little if any benefit when compared to the Clearance 2 concept in the existing Standard. A preferred approach should be to incorporate the following few items into the existing Standard FAC-003-1: (1) the RC versus the RRO; (2) the designation of a specific inspection frequency; (3) the Gallet equation; and (4) the applicability to National Forest Service lands.
Individual
E Hahn
MWDSC
Yes
Requirement R4.uses the phrase "notify the control center holding switching authority for the associated transmission line" when a vegetation condition is confirmed which is likely to cause a Fault. Switching jurisdiction may be assigned to a manned substation located closer to a line rather than a remote 24/7 manned control center. However, the switching substation will notify its control center. The control center may need to notify and coordinate with its Balancing Authority or neighboring control centers. Suggest changing the phrase as follows: "notify the appropriate control center(s)for the associated transmission line"
Group
FirstEnergy
Sam Ciccone
No
We do not support replacement of the term Active Transmission Line Right of Way with Footnote #2. Since the term "active transmission line ROW" is used in the requirements, compliance section, and VSLs, and since the drafting team has a very definite view of what this term means, the term

should be a definition included in the NERC Glossary. Also, since ROW is defined in the NERC Glossary, it further supports the reasons this term should also be defined. Therefore, we suggest the team revert back to the Draft 3 proposed NERC Glossary term. Lastly, we do not support the addition of Table 3. We believe this adds unnecessary prescriptiveness to the requirements. It is also not clear if this Table was intended to be mandatory because the only reference in the table is in Footnote #2. If the SDT feels this table is a useful tool that should be included in the standard, then we suggest adding it to the Guidelines section as optional information. Also, reference to this Table 3 in the Active Transmission Line ROW definition should be removed.
Yes
While we agree with the changes proposed, we would recommend that the list contained in the "Other" section should be revised to include judicial actions such as injunctions. While this is not a natural occurring situation, it is certainly one that will prevent an entity from removing vegetation when needed or desired.
Yes
Although we agree with the language of M1 and M2 for the proposed R1 and R2 in the standard being balloted, we support the alternate versions of R1 and R2 (see comments in Question 6) and wish to see M1 and M2 developed for the alternate R1 and R2.
Yes
Yes
Alternate version of R1/R2
Although we agree with the alternate version of R1/R2, we have the following comments: 1. We assume that R1 and R2 will be written similar to the current proposal with regard to IROL (High VRF) and non-IROL (Medium VRF) transmission lines, respectively. This should be clear after changes have been made to the standard before the final ballot. 2. Although the SDT states that it "suggests similar language as found in the posted draft for measures M1/M2 may be appropriate with this alternate R1/R2", we are not clear how these measures will be written and would like to see a draft of the measures so we can review and comment. 3. The alternate requirements appear to be "planning" in nature instead of "real-time"; we assume the intention of the SDT was the latter. Therefore the requirements should be revised with language that is "real-time" in nature.
VSLs proposed by the VM SDT
FE supports the VSL proposed by the SDT. We believe these have been developed in accordance with the FERC approved VSL guidelines and represent the appropriate violation levels for situations of varying probabilities. History has proven the grow-ins are the biggest cause of vegetation contact issues, and fall-ins and blowing together vegetation are very hard to predict and control and should be at lower violation levels. Although we believe that an encroachment into the MVCD that causes no system disturbance should not be penalized if an entity takes immediate action to restore the minimum clearance, the assignment of a Lower VSL is appropriate. We believe that the NERC staff opinion that this situation warrants a High VSL does not demonstrate thorough rationalization because it fails to consider the consequences that would place a severe monetary penalty on an entity for a situation that did not cause a fault, outage, or cascade of the BES. Furthermore, it is clear from the bullet points under R1 and R2 of the proposed standard language that the SDT intended that an encroachment with a sustained outage is different than and encroachment without a sustained outage otherwise they would not have specified the bulleted situations in detail. Had the SDT intended for there to be only two violation severity levels they would have only specified two bullet items: an encroachment with a sustained outage and

an encroachment without a sustained outage. The requirements are the only tools the drafting team has to specify its intent in this area and the approach they used is reasonable to provide these levels of differentiation.
Yes
FE has the following additional comments: 1. In the SDT consideration of comments from Draft 3, it was indicated that "The subcommittee will ask that NERC's legal department write a statement for addition to each standard to clarify which parts/elements of the standard are mandatory and enforceable and which are provided only as information". We would appreciate this statement be placed into the standard before the final ballot so stakeholders have an opportunity to review and comment on the wording. 2. We cannot comment on the Technical Reference Document since the latest draft was not posted for review. Does NERC intend to post this at a later time? If so, we ask that NERC give the industry enough time to adequately review the document so that we can provide quality feedback. 3. In the Guidelines and Technical Basis Section, in the first paragraph of Requirement R5, second sentence, the word "temporarily" should be removed since it was removed from the requirement.
Group
Kansas City Power & Light
Michael Gammon
No
This needs to be a defined term since the Standard uses that as a basis for use with Table 3. Using this term as a footnote does not allow the industry to weigh in on its definition. Footnotes should not be used as a means of definition or clarification. Footnotes are for references to other sources of statements or documents that support a particular thought.
No
The theme of the â€œOtherâ€☐ section are the conditions for excluding applicable transmission facilities under certain conditions. Recommend the Drafting Team consider renaming this section to â€œExclusionsâ€☐. In addition, the term, â€œActive Transmission Line Right-of-Wayâ€☐ is capitalized in the â€œBackgroundâ€☐ section. If it is determined this term should not be a definition, then this should be lower case.
No
In response to the informal comment period, the SDT is clear that it believes the use of encroachment as a basis for determining the effectiveness and compliance of a vegetation management program. The purpose of this Standard is to identify the criteria for effective monitoring of vegetation in transmission right-of-way and to take appropriate actions when that monitoring identifies the need to â€œclearâ€☐ vegetation to prevent potential transmission facility outages resulting from contact with vegetation. These proposed Measures as written do not give credit to the Transmission Owners for effectively monitoring their systems and taking appropriate actions in regard to vegetation clearing. Why does it make sense to punish and penalize a Transmission Owner for discovering an encroachment when they take the appropriate actions to remedy the condition before any facility outage occurs that results in compromising the reliability of the Bulk Electric System? These Measures and Standard should recognize the good practices of effective response to a vegetation condition and penalize ineffective response. Highly recommend the SDT consider including appropriate language to recognize effective remedial actions by Transmission Owners and by doing so, recognize effective efforts instead of punishing them. In addition, proving encroachments have not occurred will pose audit challenges in determining that encroachments have not occurred for the Auditors as well as Registered Entities. If no encroachments occur, then there is nothing to report or record. This is a weak platform to stand compliance on. Facility interruption events caused by vegetation contacts is definitively measurable and recordable. Recommend the SDT reconsider the concept

of compliance with FAC-003 on the basis of sustained outages.
No
It is unclear that this requirement may utilize the industry practice of â€œruling spanâ€☐ methods to determine the vegetation clearances for a transmission facility. â€œRuling spanâ€☐ methods are used to determine the construction design for transmission facilities and includes maintaining safe clearance distances. This requirement could be interpreted as being applied to every individual span to determine vegetation clearances for a transmission facility which would not be practical.
No
This requirement is in direct conflict with the â€œexclusionsâ€☐ as described in section 4.4. Section 4.4 makes it clear that effects of â€œmajor stormsâ€☐ on a vegetation programs efforts will be allowed as an exclusion toward compliance with these requirements, yet, R7 does not allow any encroachment due to modifications to a vegetation plans efforts due the â€œMajor Stormsâ€☐ (second bullet) or â€œWeather conditions/Accessibilityâ€☐ (bullet 6). Please explain what is intended here that is different than what was intended in section 4.4. In addition, this presents some audit difficulties regarding the notion of detecting a â€œmodified work planâ€☐. Once a work plan is altered and new objectives are laid out, that becomes the plan and the plans that were replaced may be discarded since they would be of no value. Further, what difference does it make to track or monitor any changes to a work plan provided effective vegetation management is maintained? Recommend the SDT consider removing the language regarding â€œwork plan flexibilityâ€☐ as this may suggest and impose an unnecessary compliance burden on Registered Entities and Auditors.
Alternate version of R1/R2
Prefer Alternative E from the list above. Please clarify the meaning of sway in Alternative E. Is that wind blowout?
VSLs proposed by the VM SDT
Although the Drafting Team is favored here, it makes little sense in the NERC Staff VSL to have an encroachment with no sustained outage as a HIGH VSL. No compromise of the real-time reliability of the bulk electric system occurred. How could that be a HIGH? If it is determined to use the VSLs proposed by NERC Staff, it is recommended to change the HIGH VSL to LOWER.
Yes
1. Part R4.3, â€œEnforcement, under Section 4, â€œApplicabilityâ€☐, is confusing as to why it is needed. What is the intended purpose of this part? It is clear that each Requirement, Measure, VRF and VSL when adopted by the NERC BOT and FERC become mandatory and enforceable on the declared effective date(s). There is no need for Part R4.3 to reinforce the compliance enforcement dictated by the established NERC Rules of Procedure. 2. Requirement R4: The requirement is clear to notify the appropriate control center regarding conditions that might cause a fault on a transmission facility. The requirement should be clear, this for the Transmission Owners applicable lines and recommend the SDT modify the language in R4 to that end. In addition, there is no action other than notification in regards to this operating condition. Highly recommend the SDT consider adding language to take â€œimmediate actionsâ€☐ to remedy the vegetation condition and remove the threat. 3. Requirements R5 & R7 are not clear in that they are for the Transmission Owners applicable lines. This has been a common theme throughout this Standard and by the omission of this language, it is not clear that the intended scope of the requirements do not go beyond the applicable lines.
Group
NERC Staff
Mallory Huggins

Yes
No
NERC staff does not support the language in the Other Section. Staff believes that the force majeure provision is unnecessary and calls into question whether NERC and the regions have enforcement discretion to take such things into account in applying other standards that do not include this type of provision.
No
With respect to both M1 and M2, NERC staff finds the â€œacceptable forms of evidenceâ€☐ incomplete. To assess compliance, the auditors would also need to see the processes and procedures identified under Requirement R3 and the annual work plan under Requirement R7 to see how the entity planned to prevent sustained outages and what the entity had done to implement that plan. Finally, what is the purpose of the following sentence?: â€œIf an investigation of a Fault by a qualified person confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered a Real-time observation.â€☐ Recommend adding each report of a real-time observation of encroachment into the MVCD to the periodic data submittal.
No
The removal of programmatic details from R3 renders the auditing task much more difficult. How does one assess the quality of the program except through the results required in R1 and R2? Since maintaining specific cut-to clearances is not required, there is much greater subjectivity in application that greatly complicates the auditor job. If the team does not want to limit the available approaches, it could provide flexibility by offering an array of deterministic formulas or approaches for maintaining vegetation. This might include maintaining vegetation to remain within a certain height from the ground given maximum sag distances. Additionally, this requirement does not seem to require the entity to actually follow its policies and procedures (unlike, for instance, R7). What is a violation here? Not having the documented procedure(s) OR whether the documented procedure(s) actually demonstrate that the entity can prevent encroachment? NERC staff is also concerned with some of the language in M3. Consider the following modification: â€œThe Transmission Owner will have procedures, processes, or specifications as identified in Requirement R3, records showing work done to support its annual work plan identified in Requirement R7, and its quarterly vegetation reports, to demonstrate that it can prevent encroachment into the MVCD.â€☐ Finally, with respect to the Rationale associated with R3, how would NERC enforce poor intent or a poor indication of competency (especially if the entity was performing well)? Recommend: Provide a basis for evaluating whether the Transmission Ownerâ€™s procedures, processes, or specifications used to maintaining vegetation are achieving that goal. There may be many acceptable approaches to controlling vegetation so that it does not encroach into the MVCD. And one small copyedit: â€œinterrelationshipsâ€☐ should not have a hyphen.
No
This is the first instance in which an annual work plan is discussed. It would appear necessary to first develop an annual work plan component of the overall vegetation management program. There should also be some performance review or expectation that the annual plan as implemented achieved the intended program objectives, or that modifications would be necessary. Does R7 require both that a Transmission Owner has an annual vegetation work plan AND that it completes the work plan? Detail is required as to what is expected in the work plan, as there is currently no basis to judge whether the work plan is adequate or not adequate. And what does a modification entail? Does this mean reduction of performance, delay in performance, or complete postponement of performance? NERC staff is also concerned with the list of examples one might use to modify

an annual plan. Several of these items should not pose any greater risk to vegetation contact and render the requirement virtually unenforceable. It provides a wide array of reasons to postpone vegetation management and may make it a very low priority for an entity: -â€œRescheduling work between growing seasonsâ€☐: This could be an honest change (if there are unexpected seasonal changes) or it could reflect bad initial planning. If there will be occasion for auditors and investigators to distinguish, there should be guidance on differentiating. -â€œCrew or contractor availabilityâ€☐: This could be an honest change (if there is an unexpected labor dispute or if crews are needed to help a neighboring utility during an unexpected emergency) or it could reflect bad initial planning. If there will be occasion for auditors and investigators to distinguish, there should be guidance on differentiating. Alternatively, it could be removed from the list as it is within the exclusive control of the Transmission Owner. -â€œIdentified unanticipated high priority workâ€☐: This could be an honest change or it could reflect bad initial planning. If there will be occasion for auditors and investigators to distinguish, there should be guidance on differentiating. It is also vague and would necessitate a judgment call for enforcement. -â€œPermitting delaysâ€☐: Annual plans should account for anticipated permitting schedules and maybe even add a factor for uncertainty. It is a planning issue for the entity and should not be an acceptable excuse for not conducting vegetation management. -â€œLand ownership changedâ€☐: If a landowner has the ability to affect the reliability of the bulk power system, the landowner should be subject to the reliability standards. A registered entity should be responsible for the land in its ROW, especially if it has turned control of the land, and the ability to affect reliability of the BPS, over to another entity or person for financial gain. -â€œFunding adjustmentsâ€☐: NERC staff is not convinced that this is a legitimate reason for adjusting an annual vegetation work plan. Economic considerations should not be a reason to delay or modify vegetation management. -â€œEmerging technologiesâ€☐: It is unclear what this example is intended to accomplish. In general, these examples should be bounded in some way to ensure that a modification due to one of their occurrences does not impart a greater risk of vegetation contact.
Draft 4 version of R1/R2
NERC staff supports the Draft 4 version. The six options listed in the alternative version of R1/R2 do not seem manageable from a utility perspective. But while staff prefers the existing language, it continues to emphasize that fall-ins from outside the ROW can impact the line and need to be taken into consideration.
VSLs proposed by NERC staff
NERC staff supports the VSLs proposed by NERC staff. The SDTâ€™s VSLs are too low, and they do not seem to differentiate between various levels of compliance. Still, staff is concerned that the difference between an encroachment that leads to an outage and one that does not is based on nothing but luck.
Yes
EFFECTIVE DATES -The first item should be re-written to â€œFirst calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval is required.â€☐ -The second item is not needed and should be removed. -The third item is okay but the phrase â€œwhere explicit regulatory approval is not requiredâ€☐ should be removed. EXCEPTIONS -Identifying a critical line and then waiting 12 months to perform vegetation management is counter to the risk avoidance strategy that the standard is attempting to accomplish. In effect, this standard permits an entity to identify a major WECC path or an IROL just prior to peak season and then not complete any vegetation management activities until just before the next season 12 months later. This is wholly inappropriate. -Using the phrase â€œan element of an IROLâ€☐ seems confusing because â€œElementâ€☐ is a term defined in the glossary.

Further, IROL is an identified limit, not a physical component. This should be reworded to say â€œa facility that is identified to be part of an interface or path impacting an IROL.â€☐ This is also seen in R1 and R2 and needs to be adjusted there as well. -For newly acquired assets, the 12 month window may be appropriate, but there needs to be a much nearer term inspection undertaken to identify â€œriskyâ€☐ vegetation. DEFINITION -The modified definition assumes the ROW is maintained, which may not be the case (for instance, if a newly acquired asset has not yet been acted upon). An entity could interpret the new definition to indicate that the new owner cannot be performing an initial vegetation inspection if the ROW has not yet been maintained. The phrase â€œmaintained transmission lineâ€☐ should be changed to â€œapplicable transmission line.â€☐ -The inclusion of the phrase â€œwhich may be combined with a general line inspectionâ€☐ is unnecessary and should be removed. In fact, the current definition does not restrict combining the inspection with other field visits, while in the proposed definition that vegetation inspection can only be combined with a general line inspection. OBJECTIVES (SECTION 3) -NERC staff is concerned that the purpose states â€œthat could lead to Cascading.â€☐ This qualifier limits the purpose of the standard, which should be to prevent vegetation-related outages. The more outages there are, the less the overall system reliability; it does not necessarily have to lead to Cascading to be significant and represent a reasonable risk to the BES. -The term â€œmaintainâ€☐ might be better than â€œimprove.â€☐ APPLICABILITY (SECTION 4) 4.1 Functional Entities -Noticeably absent from the standard is coverage for transmission facilities that connect generators to the interconnected bulk power system. As such, the team should add Generator Owners to the applicability and include such language that was proposed by the ad hoc team: transmission facilities that connect generators to the bulk power system that exceed two spans from the fence-line of the generating plant; coupled with the previous discussion, this provides complete coverage for all transmission facilities and switchyards and substations. This is what is needed to ensure no gaps in vegetation management coverage. 4.2 Facilities -The identification of critical facilities herein does not recognize the overarching criteria that are being developed in support of the PRC-023 order, and in some respects, in response to Order 693 directives to define the criteria for â€œcritical facilities.â€☐ The FAC-003-2 SDT should work in conjunction with the PRC-023 team, which is establishing a set of criteria for identifying critical facilities such that the outcome across all NERC standards is consistent. -â€œTransmission lineâ€☐ should be capitalized as a NERC-defined term. -4.2.4: This exclusion seems strange. It would appear that there are no expectations for vegetation management in switchyards, which is unacceptable. We should be able to develop language that requires that a Transmission Owner or Generator Owner maintain vegetation within fenced areas of the switchyard, station, or substation to the same clearances as one does for the ROWs, without necessarily obligating them to an annual cycle of inspection or management. REQUIREMENT R4 -â€œQualified personnel" should be defined. In the Rationale, some examples are listed, but who else counts as â€œqualified field personnelâ€☐? -â€œAt any momentâ€☐ is an unnecessary qualifier and should be removed (same for M4). -With respect to the phrase â€œintentional time delay,â€☐ intent is a tricky thing to prove. Most standards set clear timelines which kick in regardless of intent, because it diminishes reliability to base a standard on intent. The SDT should consider doing so here. REQUIREMENT R5 -NERC staff is confused by the overall purpose of this requirement. It appears to be a defense to a possible violation for failure to perform some planned vegetation work, but it flips it around and makes it a requirement. A better approach would be to just deal with this in addressing the mitigating/aggravating factors under a violation of R1 and R2. -The team should be more specific with respect to expectations for â€œcorrective action.â€☐ There needs to be an expectation that the corrective action needs to maintain an equivalent level of performance consistent with the intent of the vegetation management program. This could include, for example re-rating lines to reduce max sag until the condition is rectified, enhanced inspection cycles to monitor conditions, etc. It would be useful to define a metric for the success of corrective actions. -The team should be clearer on what constitutes a â€œconstraint.â€☐ Is it only legal constraints? One interpretation could be resource constraints, which would certainly not be appropriate in this context. The phrase â€œdue to constraintsâ€☐ is also used in the Rationale section. In this context, â€œconstraintâ€☐ appears to mean congestion on a transmission line. This seems very different from being â€œconstrained from performing planned vegetation work.â€☐ In fact, the existence of congestion on a line does not necessarily create risk. We would not want entities to make the economic determination that they will put off required vegetation work because it would cost too much in energy sales profits. REQUIREMENT R6 -It would appear necessary to require the use of the inspection information to guide or modify program development as is identified in the Rationale box accompanying the requirement. This is referred to in R7 but is not identified as an expectation from R6. -What are "all applicable transmission lines"? Are those lines covered by both R1 and R2? Clarify this. -â€œOnce per calendar year" requires more guidance. Would two inspections on 12/31/2010 and 1/1/2011 satisfy this requirement? Shouldn't there be a requirement to space these inspections out? Recommend: once per calendar year with no more than 15 months between inspections. -The last sentence of R6â€™s Rationale states that â€œTransmission Owners should consider local and environmental factors that could warrant more frequent inspection.â€☐ But the way the requirement is written, there is no basis for requiring anything more frequent than once per calendar year. If the intent is to have stricter timelines for different registered entities, then the standard would need to be revised. COMPLIANCE Additional Compliance Information/Categories of Sustained Outages -Category 3 (Fall-ins from outside the ROW) should be reinstated. Even if it is not required by the standards, Category 3 reporting should be kept. -There is currently a public bulletin to encourage Transmission Owners to report Category 1 and 2 outages within 48 hours. The SDT should consider adding this as a requirement and including it in the new standard as such. VSLs -The VSL for R3 should be shifted to an approach that simply counts the missing elements: lower = missing one element; moderate = missing two elements; high= missing three elements; severe = not having documents. -The VSL for R4 uses the phrase â€œvegetation threat,â€☐ which needs to either be conformed to the text of the drafting team or defined. This VSL also uses the phrase â€œintentional delayâ€☐ A truly intentional delay should be labeled as severe, not just high. (And as already stated, intent is a very tricky thing to prove.) -For the VSL for R5, there may be ways to differentiate violations based on whether the entity identified appropriate corrective actions (versus missing obvious alternatives), attempted corrective actions but failed, considered alternative corrective action, etc. -For the VSL for R6, the SDT should differentiate between the criticality of different lines. At the very least, a failure to inspect R1 lines should be a more severe violation than a failure to inspect R2 lines. -The VSL for R7 should perhaps be differentiated based on whether the incomplete work related to critical versus non-critical or less critical lines (i.e., R1 lines vs. R2 lines). GUIDELINES AND TECHNICAL BASIS R1/R2 -â€œIf an investigation of a fault by a qualified person confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered a Real-time observationâ€☐: This is an important statement and should be included as part of the requirement itself. R3 -With respect to the phrase â€œan adequate transmission vegetation management program,â€☐ the standard talks about factors to consider, but the requirement does not include any provisions on which to base a determination of adequacy. NERC staff believes it should. -The guideline states, â€œThis approach provides the basis for evaluating the intent,

allocation of appropriate resources and the competency of the Transmission Owner in managing vegetation,â€☐ but nothing in the requirements actually provide explicitly for such evaluations. R4 -â€œCellular service or two-way radio disabledâ€☐ should not be considered an acceptable unintentional delay. This seems to be within the entityâ€™s control: there may be a difference between whether the cell service problems are due to network problems as opposed to the entity failing to charge the phone or pay the bill. -â€œRemote field locationsâ€☐ should not be considered an acceptable unintentional delay. This is not entirely beyond the registered entity's control. There may be a difference between a work site that is isolated from radio or cellular networks versus the fact that the employee simply left the radio in the truck. -â€œVegetation-related conditions that warrant a responseâ€☐ should be defined in the standard. -It is not clear to NERC staff that a lineman or an arborist is capable of completing â€œan assessment of the possible sag or movement of the conductorâ€☐ out in the field in real time. However, if this is the expectation, it should be written into the requirements. -The fourth paragraph states that the â€œTransmission Owner has the responsibility to ensure the proper communicationâ€¦â€☐ Earlier in this section, however, it says that the condition of the communication system is not considered to be intentional delay. This inconsistency needs to be addressed. This sentence should also include a requirement for correcting the vegetation encroachment. -The phrase â€œminutes or hoursâ€☐ is used in the final sentence of the fourth paragraph of this sentence. This detail should be written more clearly and written into the standards. Is 24 hours still hours? What about 48 hours? R6 -With respect to the following sentence, beginning with â€œTherefore it is expected,â€☐ NERC staff is concerned that nothing in the requirement actually makes this expectation enforceable. It would be best to require each TO that experiences a vegetation related sustained outage to investigate the outage and make revisions to its TVMP if the investigation shows that the growth rates of vegetation under the TOâ€™s control do not match those anticipated in the TVMP. R7 -The second paragraph states that â€œrecent line inspections may identify unanticipated high priority work.â€☐ But the fifth bullet in R7 does not indicate that the higher priority work was identified in a recent line inspection. R7 should be revised to make that caveat clear. -The second paragraph references â€œModifications to the annual work plan.â€☐ Presumably, these modifications would not excuse compliance with R1, R2, and R6. That should be made clearer in the requirements. TABLE 3 -None of the requirements actually reference this table. That should be modified.
Group
Dominion
Louis Slade
No
The distances proposed in Table 3 â€“ Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW may not be consistent with the centerline distances cleared and maintained by the TO. For example, a TO maintaining 75â€™ from centerline for a 500kV circuit would be required to clear and maintain an additional 12.5â€™ to meet the proposed standardâ€™s requirement. We suggest either allowing individual TOs to maintain active ROW widths consistent with their normal clearing/maintenance practices, going back to Draft 3â€™s definition of Active Transmission Line Right-of-Way, or changing the footnote in Draft 4 to read: A strip or corridor of land that is occupied by active transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities. However, the portion of the ROW that has been cleared must at least meet design clearance requirements such as National Electric Safety Code or other design criteria, for the reliable operation of active facilities.
Yes

Yes
Yes
Although we agree with the intent of the proposed language, we feel the requirement should be revised to read: Each Transmission Owner shall document the procedures, processes, or specifications it uses to prevent the encroachment of vegetation into the MVCD. Such procedures, processes, or specifications shall consider the dynamics of a transmission line conductorâ€™s movement throughout its Rating and Rated Electrical Operating Conditions and the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the Transmission Ownerâ€™s applicable lines.
Yes
Draft 4 version of R1/R2
The alternate language proposed above suggests that methodologies typically incorporated into processes, procedures, or specifications (as required by R3) should also be included into performance-based requirements R1 and R2. The incorporation of this language into R1 and R2 would change these requirements from performance-based requirements to hybrid performance/competency-based requirements. The intent of R1 and R2 is to define a failure to prevent encroachment into the MVCD. Ensuring that a TOâ€™s processes, procedures, or specifications demonstrate adequate means of protecting conductors falls under R3, which incorporates transmission conductor and vegetation dynamics and interrelationships. Therefore, methodologies employed to manage the floor of active transmission ROW should be incorporated into the documentation required by R3 and proof that vegetation was managed in accordance with processes, procedures, or specifications to prevent encroachment into the MVCD will be demonstrated by compliance with R1 and R2.
VSLs proposed by NERC staff
As all parts of R1/R2 seem to contribute equally to the intent of the requirement â€“ shall manage vegetation to prevent encroachment that could result in a Sustained Outage - NERCâ€™s proposed VSLs best address noncompliance with the requirements.
Yes
In R4 and M4, the phrase "without any intentional time delay" has been added. We recommend removing this language from the requirement as it is not possible to measure intent.
Individual
George Czerniewski
Consolidated Edison Company of New York Inc
Yes
The same verbiage in footnote number 2 should appear below Table 3 to avoid any confusion.
Yes
Yes
Yes
Yes
Draft 4 version of R1/R2
Consolidated Edison Company of New York, Inc prefers the Draft 4 version. The wording in the VSLs should be modified for both Requirements to

include the phrase 'manage vegetation'. The phrase 'manage vegetation' requires a utility to take specific action to prevent encroachments/outages.
VSLs proposed by the VM SDT
The wording in the VM STD VSLs should be modified to include whether or not the TO managed any vegetation on that particular line. A more severe VSL should be assigned to any encroachment or sustained outage that was caused as a result of a TO not performing any vegetation management activities on that line. For example, if vegetation management activities were completed on 80% or 90% of the line and additional work was in progress on the remainder of the line but an encroachement or sustained outage occurred on the spans that were scheduled to be done as part of the annual plan, the TO should be held accountable for this but at a lower severity level.
Yes
In R5, the SDT should better define the phrase 'where a transmission line is put at potential risk due to the constraint.' This is rather vague and could lead to inconsistent practices between utilities. Con Edison defines all undesirable species on the full width of the ROW as 'potential risks to the transmission line' regardless of height or location at the time of vegetation management. Interim corrective action should only be required when the potential risk is approaching the imminent threat classification.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on Initial Ballot — Project 2007-07 Vegetation Management FAC-003-2
Date of Initial Ballot: 7/9/2010 - 7/19/2010

Summary Consideration: In general, there were no common themes and as such each comment was responded to individually.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Kirit S. Shah	Ameren Services	1	Negative	(1) Need clarification on Footnote number 2 and Table 3 : Does this mean wider ROW easements will need to be acquired to be compliant or will this apply to ROW's for new circuits going forward? (2)R7 - Funding Adjustments (increase or decrease) - need more description to imply only when planned vegetation work is "over and above". (3) R5 - What constitutes a "potential risk"? Breaking the MVCD or getting close to it? (4) R7 - No work plan can ensure that NO vegetation encroachments will occur; can language be added similar to "to ensure that no vegetation encroachments 'from vegetation within the active right of way' occur within the MVCD"?
Response: **(1) No, the SDT has re-established the concept of an Active Transmission Line ROW by changing the definition of Right of Way with the same principles which was almost universally accepted by industry. After thorough analysis of potential modifications to Table 3 and other alternatives, the team found no specific, prescriptive, or formulaic language which can be applied across the US, Canada and Mexico, thus the team reverted to the Active Transmission Line ROW, removed Footnote 2 and Table 3.** **(2) The SDT limits the reasons for plan adjustment by whether the changes place the system at risk of a violation of the MVCD as defined in R1 and R2.** **(3) The SDT recognizes that defining any risk is subjective. Removing the term does not change the fact that each TO must determine the risk and respond accordingly.** **(4) The SDT has incorporated your suggestions.**				
Danny McDaniel	Cleco Power LLC	1	Negative	1. Encroachment into the MVCD should require the owner to take immediate corrective action to mitigate the threat. But such an encroachment should not be reportable as a violation. Owners may be hesitant to report if they known it is a violation. Recommend the SDT consider modifying the measures for R1 and R2 to be applicable only in the interruption of transmission facility or allow the reporting but don't make it a violation of compliance. R4 states "Each Transmission Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated transmission line when qualified
Bryan Y Harper	Cleco Utility Group	3	Negative	

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td>Matthew D Cripps</td><td>Cleco Power LLC</td><td>6</td><td>Negative</td><td>personnel confirm the existence of a vegetation condition that is likely to cause a Fault at any moment" 2. In R4, the use of "intentional" is a vague term. As other standards prescribe, set a time at which the control center should be notified. R5 states: "Each Transmission Owner shall take corrective action when it is constrained from performing planned vegetation work, where a transmission line is put at potential risk due to the constraint." 3. In R5, the use of "potential risk" is a vague term. R5 should read as follows: Each Transmission Owner shall take corrective action when it is constrained from performing planned vegetation work. R7 states: "Each Transmission Owner shall complete the work in an annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD ...." 4. The first sentence should not include the phrase "to ensure no vegetation encroachments occur within the MVCD" since the requirement is to do the work in the work plan. The added phrase adds ambiguity, e.g., if there is an encroachment, is R7 violated since it does not meet the "ensure" phrase? Would this cause a double jeopardy situation with R1 and R2?</td></tr>
<tr><td colspan="5">Response:
1. The SDT discussed this issue at length. However, NERC and FERC interpret vegetation growing into MAID as too great a risk to allow. While MAID is replaced with the MVCD the risk is still there.
2. The SDT debated a set time limit. The team could not find a time that would fit all situations. Intentional would apply if a TO withheld notification after having confirmed that risk conditions exist.
3. The SDT removed the vague language.
4. There are opportunities for double jeopardy between R1/R2 and R7 without this language. The occurrence of double jeopardy has not been born out.</td></tr>
<tr><td>Saurabh Saksena</td><td>National Grid</td><td>1</td><td>Negative</td><td rowspan="2">1. The recent addition of a centerline distance to edge of Active ROW is not acceptable to National Grid. In many areas we use design standards that allow a much lesser ROW width with no compromise to “cleared width” or tree related reliability of the line. Instead of using the term “Centerline” as referenced on Table 3, the use of “outer phase” or “phase closest to tree line” would be more appropriate. 2. National Grid also has issues with the term "easements" in the definition and seek clarification on several questions - is there a reason the Active ROW only includes easements, not fee ownership, license or some other right to occupy and manage the ROW? Would Active ROW include “danger tree rights” on land?</td></tr>
<tr><td>Michael Schiavone</td><td>Niagara Mohawk (National Grid Company)</td><td>3</td><td>Negative</td></tr>
<tr><td colspan="5">Response: 1&2. The SDT thanks you for your comments. Based on your comment and others, the , the SDT has re-established the concept of an Active Transmission Line ROW by changing the definition of Right of Way with the same principles which was almost universally accepted by industry. After thorough analysis of potential modifications to Table 3 and other alternatives, the team found no specific, prescriptive, or formulaic language which can be applied across the US, Canada and Mexico, thus the team reverted to the Active Transmission Line ROW, removed Footnote 2 and Table 3.</td></tr>
<tr><td>Claudiu</td><td>GDS Associates, Inc.</td><td>1</td><td>Negative</td><td>All comments have been included in the NERC comment form.</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
Cadar				
Response: **Please refer to the SDT responses on the comment form.**				
Michael Gammon	Kansas City Power & Light Co.	1	Negative	Although the proposed FAC-003 standard has many improvements and advancements that are desirable over the existing FAC-003 standard, the handling and treatment of encroachments as proposed without consideration of recognizing an organizations efforts in responding to an encroachment situation makes this proposal less desirable and is a major concern regarding the risk that the associated penalties and assessments place on organizations.
Scott Heidtbrink	Kansas City Power & Light Co.	5	Negative	
Response: The SDT thanks you for your comments. Zero tolerance for vegetation caused outages is a stated goal of FERC and NERC as it relates to this standard. Quote from NERC: ***Vegetation Management*** *— While four transmission outages due to vegetation occurred in a single afternoon five years ago, preliminary data suggests that only six such outages occurred in the first six months of 2008 – none of which caused customers to lose power. Transmission line outages due to vegetation contact are still a cause for concern, however, and this remains a top priority for NERC. Through its standards and compliance enforcement, NERC now has a zero-tolerance policy in place, where the goal is to correct issues that may arise long before any customers are affected.* **This policy is part of FAC-003-1 and in concept did not change with the proposed version. The SDT recognizes this concern and has developed gradation taking into account line criticality in VRF's and type of outage not contained in the current version FAC-003-1. Finally, It is also important to note that each and every incident or potential violation is investigated and addressed based on the specific circumstances surrounding the particular event. These investigations should necessarily take into consideration and recognize the utility's individual efforts in responding to an encroachment situation.**				
Thomas R. Glock	Arizona Public Service Co.	3	Negative	APS supports retention of FAC-003-1 as currently effective, as it is working well for the industry. APS does not support a change to this standard for the following reasons: o The minimum clearances must be sufficient to avoid any sustained vegetation-related outages for all applicable conditions. ? . ? Clearance 1 should remain in the standard as it ensures clear direction to the utility on how the system is to be maintained, and provides assistance to the Transmission Owners in dealings with federal land agencies on vegetation management issues. Elimination of the discretion in clearance 1 will significantly degrade this support. ? ANSI-A300 should remain in the standard. Though simply a footnote in the currently effective version, ANSI-A300 should be a requirement in the standard. Relevant Registered Entities should be held to following ANSI A-300 standards and BMP's for best management practices. o APS does not agree with the removal of 'fill in the blank' components where the Transmission Owner determines the requirement with no limits or direction. Examples include and "personnel requirements" in version 1. The SDT removed this requirement from the current version. ? Personnel qualifications should be remain a requirement. The standard should recognize certification programs through the International Society of Arboriculture that certify a minimum level of competence to manage

Voter	Entity	Segment	Vote	Comment
				a vegetation management program which required ongoing training and education to keep up with the latest technologies on UVM. ? There are other standards that require qualifications and training. ? The revised standard dilutes accountability for maintaining the full width of utilities easement. The active ROW should be wide enough to prevent outages caused by grow-in and blow-in events. ? The changes to R1, allowing a real-time observations to evidence encroachments, does not take into account all rated conditions and the time the recording was made. Real-time observations will not account for changing conditions and increase in load. Available technologies, such as LIDAR, can simulate all-rated conditions, contour and tree height to remove these potential trees hazards before an outage occurs. ? The utilities should be required to inspect all the lines annually. ? The standard should include a footnote that provides that a utility will not be held accountable for not completing its annual work plan if federal or state agencies fail to approve annual work plans within 90 days of submittal, or that takes into account the time it takes the utility to get approval.

Response: Thank you for your comments.

- **The SDT is changing the Standard in response to the SAR. The success of the existing standard will be preserved and enhanced with this revision.**
- **If vegetation is maintained as required in this draft of the standard in requirements R1 and R2, then no vegetation-related sustained outages, caused by vegetation from within the ROW, within the control of the TO can occur.**
- **Clearance 1 was a fill-in the blank requirement and did not provide the TO any new easement rights, or land permit rights across any lands whether those land be privately owned or publicly owned; therefore Clearance 1 remains removed from this draft. Furthermore, the relevance of Clearance 1 depends on several other factors such as length of maintenance cycles, inspection frequency and growth rates. R3 is now used as a more comprehensive method to address these concerns in lieu of a Clearance 1 requirement.**
- **In order to meet the SAR FAC-003 is required. ANSI-A300 is not sufficient to meet the SAR requirements and contains many elements that do not need to be related to transmission system electrical reliability.**
- **The SDT suggests that the submittal of a NERC SAR on the PER standards be considered to address any proposed personnel qualifications, certifications or training issues.**
- **The SDT is following NERC guidelines as they understand them.**
- **The SDT has re-established the concept of an Active Transmission Line ROW by changing the definition of Right of Way with the same principles which was almost universally accepted by industry. Outages arising from vegetation from outside the ROW are not violations of the standard. The SDT had determined this to be the most appropriate assignment of an area of maintenance responsibility considering the numerous variations in easements and permit rights across North America.**
- **The Standard requires the maintenance to be performed such that loading to Rating and Rated Conditions, and the dynamics of sag and sway are taken into consideration. Additionally any real time observations of encroachments into the MVCD are to be reported as violations of the standard. The SDT does not see the need to be prescriptive as to the technology or tools the TO used to be compliant with the Standard, but is confident that if the vegetation in maintained such that no encroachments are ever observed, and no outages are ever occur, then the reliability purpose of the standard will be fully accomplished. Furthermore, the results from a LIDAR survey are temporal in nature.**

Voter	Entity	Segment	Vote	Comment
Any program relying on LIDAR would incur a substantial cost with a long term commitment that may not be justified for many Transmission Owners. • **FERC requested a defined period for inspection. The SDT agrees with you that annual inspection is required. Therefore the SDT has made annual inspections a Requirement of this Standard. As to all lines versus applicable lines, FERC has accepted the 200 kV bright line for this standard. They did order the SDT to ensure that no sub-200 kV lines that are important to the Bulk Electric System are missing from the Applicability of the standard. The SDT has incorporated a FERC accepted test (as found in the referenced Standard) to make sure no such important lines are missing.** • **The SDT agrees that erroneous obstacles to compliance with the standard should be addressed. However, they cannot be resolved in this forum, or through language inserted in this standard. This Standard places requirements on the Transmission Owners, not on landowners. There is no legal mechanism for this Standard to take rights from property owners and assign them to the Transmission Owner.**				
John J. Moraski	Baltimore Gas & Electric Company	1	Negative	BGE feels that the new standard does nothing to improve reliability over the existing standard. Furthermore, it could be argued that it potentially diminishes reliability, based on the new MVCD vs. Clearance 2 guidelines. It also includes requirements which could be perceived as being more confusing than the existing requirements in the current standard, e.g., the Active Right-of-Way, Calendar Year Inspections, etc. The new standard, If adopted, would almost certainly require a complete restructuring of all TVMPs and related compliance processes, with no commensurate value-added for individual utilities or the industry in general. In addition, it would do little to enhance the overall intent of the standard, which is to improve vegetation-related transmission reliability in North America.
Response: The SDT thanks you for your comments. The SDT believes the proposed version addresses concerns outlined in FERC Order 693 and improves reliability of the BES. The industry overwhelmingly agrees the MVCD based on the Gallet Equation is superior to that of the Clearance 2 fill-in the blank requirement in the current version and in fact can be a greater distance depending on the basis used for Clearance 2 determination. Based on your comment and others, the SDT has re-established the concept of an Active Transmission Line ROW by changing the definition of Right of Way with the same principles which were almost universally accepted by industry. After thorough analysis of potential modifications to Table 3 and other alternatives, the team found no specific, prescriptive, or formulaic language which can be applied across the US, Canada and Mexico, thus the team reverted to a ROW definition, removed Footnote 2 and Table 3. While it is true that any change to the standard may result in changes to current documentation of practices and procedures (such as the TVMP), the SDT believes changes will be minor and be an improvement.				

Voter	Entity	Segment	Vote	Comment
Paul Rocha	CenterPoint Energy	1	Negative	CenterPoint Energy believes the proposed FAC-003-2 is not a performance-based standard, despite being labeled as such, because it remains too focused on processes and procedures. CenterPoint Energy fails to see much difference in the approach from the current Standard. CenterPoint Energy believes a performance based requirement would provide performance criteria that an entity would be measured against. An example of a performance based requirement would be the following: R1. “Each Transmission Owner shall manage vegetation to prevent encroachment that results in no more than one (1) Sustained Outage per XXX circuit miles of applicable lines within any twelve (12) month period.” M1. Each Transmission Owner has evidence that it had no more than one (1) Sustained Outage per XXX circuit miles of applicable lines within any twelve (12) month period. Examples of acceptable forms of evidence may include dated reports of vegetation-related Sustained Outages or dated attestations as to no vegetation-related Sustained Outages have occurred.
Response: The SDT thanks you for your comments. FAC-003-2 is a “results based standard” (RBS) with a stated objective to prevent outages that could lead to cascading. Any requirement that has an allowance for a certain number of outages does not meet that objective.				
Russell A Noble	Cowlitz County PUD	3	Negative	Cowlitz votes negative with reluctance over two items: 1. Requirement R4 has a qualitative nature in the statement “without intentional time delay” which will leave room for subjective judgment on the part of the auditor in determining intent or the state of mind of the Transmission Owner. Cowlitz understands the need to communicate to the control center a vegetation condition that may cause a Fault at any moment as soon as possible. In this light, it is not possible to set a quantitative time limit for this report to occur for all occasions. In one scenario, a very short time limit may be arguable due to the proximity of available radio/telephone communications. However, in another remote situation it may take up to several hours to access communication equipment after discovery. Compounding the problem is the need to document the time of day versus location progress of the vegetation inspector to establish a discovery time stamp; this is not covered in M4. Cowlitz suggests the following changes (see standards VAR-002-1, IRO-006-3, TOP-003-0, TOP-

Voter	Entity	Segment	Vote	Comment
Bob Essex	Cowlitz County PUD	5	Negative	007-0 for similar verbiage): R4. Each Transmission Owner shall notify the control center holding switching authority for the associated transmission line when qualified personnel confirm the existence of a vegetation condition that is likely to cause a Fault at any moment as soon as possible, but no longer than one hour with the following exception: In areas where communication with the control center is not possible within one hour due to lack of radio/telephone service, the Transmission Owner shall document these areas along with the reasonable time frame for reaching radio/telephone service. 2. Cowlitz agrees with United Illuminating in that R7, as proposed, requires a VMP to be completed to ensure no encroachment occurs. The Supplemental Reference for R7 does not describe the requirement of the annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. The Reference states the requirement is established to diminish the risk of encroachment; very different from ensuring no encroachment. In the reference for R7 the word “ensure” is only used to describe that flexibility in the VMP is allowed to ensure the reliability of the Transmission System. M7 is measuring work plan completion not the prevention of encroachment. United Illuminating and Cowlitz suggest that R7 be changed to: Each Transmission Owner shall complete the work in an annual vegetation work plan to manage the prevention of vegetation encroachments occur within the MVCD. In this way, a violation of R1/R2 does not necessarily mean R7 is violated. The entity does not avoid a penalty for an encroachment because a violation of R1/R2 occurs for actual encroachment. If an encroachment occurs the compliance enforcement authority can review the entities vegetation management plan to determine if it is compliance with R7/M7.

Response: The SDT thanks you for your comments.

1. **The time required by the TO to report an issue is subject to many variables such as available communication for the area which could be a hike-in location with no radio or cell phone coverage. For this reason it is difficult to establish a time period which would fairly apply to all TO’s.**
2. **Please refer to the following responses to questions (which are responsive to your reference to your conncurrence with the United Illuminating):**

   Question 1: Comment 12

   Question 5: Comment 6

   Question 6: Comment 44

   Question 7: Comment 14

   Question 8: Comment 39

Voter	Entity	Segment	Vote	Comment
Jason L. Murray	Alberta Electric System Operator	2	Negative	Due to slow vegetation growth rates in many parts of Alberta, not all transmission right-of-ways require annual inspection as required in R6. TOs should be able to include planned inspection cycles in their Transmission Vegetation Management Plan.
Response: Thank you for your comment. For the sake of consistency for all applicable entities, the SDT believes that an annual inspection complements the required annual work plan. The standard allows for both maintenance inspections and vegetation inspections to be performed concurrently. Additionally, annual inspections are useful to not only track growth, but also other potential issues such as identifying danger trees, landslides, erosion, and tree damage caused by animals.				
Ralph Frederick Meyer	Empire District Electric Co.	1	Negative	EDE agrees with the concers raised by United Illuminating and therefore also provides the following comments related to R7 and R4 for FAC-003-2. R4: The use of intentional time delay is a qualitative attribute and not a quantitative measure. It will lead to endless arguments over intentional versus non-intentional. EDE agrees with UI's comment: "In R4 the phrase: without any intentional time delay, is a concern. There is a time line between identification and reporting of an imminent hazard that represents the minimal time required to complete this Requirement. Any situation where the time between observation and reporting is greater than this minimal time line indicates a time delay occurred. It will be left to the compliance enforcement authority to determine if this delay was intentional or not. It is not proper for the test to be based on Intentional versus Non-Intentional. Using other synonyms such as reasonable, expeditious, prompt, immediate or without hesitation all introduce a qualitative not a quantitative attribute to the measurement. The Supplemental Reference for R4 indicates that the imminent threat requirement is measured in minutes or hours; again no guidance for enforcement. R4 would be improved with an explicit time requirement of 6 hours between observation and report. This is measurable and clear. M4 becomes Each Transmission Owner that has a vegetation condition likely to cause a Fault at any moment, as confirmed by qualified personnel, will have evidence that it notified the control center holding switching authority for the associated transmission line within 6 hours of observation." R7: R7, as proposed, requires a VMP to be completed to ensure no encroachment occurs. The Supplemental Reference for R7 does not describe the requirement of the annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. The Reference states the requirement is established to diminish the risk of encroachment; very different from ensuring no encroachment. In the reference for R7 the word “ensure” is only used to describe that flexibility in the VMP is allowed to ensure the reliability of the Transmission System. M7 is measuring work plan completion not the prevention of encroachment. EDE agrees with United Illuminating suggestion that R7 be changed to: Each Transmission Owner shall complete the work in an annual vegetation work plan to manage the prevention of vegetation encroachments occur within the MVCD. In this way, a violation of R1/R2 does not necessarily mean R7 is violated. The entity does not avoid a penalty for an encroachment because a violation of R1/R2 occurs for actual

Voter	Entity	Segment	Vote	Comment
				encroachment. If an encroachment occurs the compliance enforcement authority can review the entities vegetation management plan to determine if it is compliance with R7/M7. EDE also agrees with concerns raised by FMPA that Periodic data submittals as written are really periodic self-certifications and ought to be named such, or 100% compliance reduced to a more reasonable target
Response: Thank you for your comment. The SDT believes that it was not prudent to suggest a quantitative time element for notification in R4. The technical reference offers examples of acceptable unintentional delays for your review. Confirmation that a threat actually exists due to vegetation is key. **Based on comments, the language in R7 has been modified.**				
Robert Martinko	FirstEnergy Energy Delivery	1	Negative	FirstEnergy appreciates the hard work of the drafting team, but unfortunately we must cast a Negative vote for the standard as written. If the SDT agrees with our comments below and makes the suggested changes, we will consider supporting this standard in the recirculation ballot. In the latest Draft 4, the SDT added a Table 3 titled "Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW". We do not support the addition of Table 3 because we believe it adds unnecessary prescriptiveness to the requirements. It is also not clear if this Table was intended to be mandatory because the only reference in the table is in Footnote #2. Furthermore, the SDT did not offer any rationale for the minimum distances shown. If the SDT feels this table is a useful tool that should be included in the standard, then we suggest adding it to the Guidelines and Technical basis section as optional information with a discussion of the basis for the values chosen. The standard being balloted includes an R1 and R2 detailing requirements for managing vegetation. In addition, the SDT has asked for industry feedback on an alternate R1/R2 through the comment form which may lead to changes to the standard after this initial ballot. FirstEnergy supports the alternate R1/R2 but as we stated in the comment form, we still need to see the final verbiage of the alternate R1/R2 along with their associated measures M1 and M2 which have not yet been developed. Therefore, we cannot support the standard until the alternate R1, R2, M1 and M2 are developed.
Kevin Querry	FirstEnergy Solutions	3	Negative	
Douglas Hohlbaugh	Ohio Edison Company	4	Negative	
Kenneth Dresner	FirstEnergy Solutions	5	Negative	
Mark S Travaglianti	FirstEnergy Solutions	6	Negative	
Response: Thank you for your comment. In response to comments regarding the addition of the "Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW" Table 3, the SDT agrees to remove this table and use the new definition of Right of Way. Additionally, language in M1/M2 has been modified based on comments received.				

Voter	Entity	Segment	Vote	Comment
Frank Gaffney	Florida Municipal Power Agency	4	Negative	My biggest problem is with R1 and R2 "Each Transmission Owner shall manage vegetation to prevent encroachment that could result in a Sustained Outage of applicable lines .... Types of encroachment include: 1. An encroachment into the Minimum Vegetation Clearance Distance (MVCD) as shown in Table 2, observed in real time, absent a Sustained Outage, 2. An encroachment due to a fall-in from inside the active transmission line ROW that caused a vegetation-related Sustained Outage, 3. An encroachment due to blowing together of applicable lines and vegetation located inside the active transmission line ROW that caused a vegetation-related Sustained Outage, 4. An encroachment due to a grow-in that caused a vegetation-related Sustained Outage" One fundamental problem with all the standards is the demand for no faults, no errors, 100% compliance. Requirements 1 and 2 basically say that any vegetation related outage, except for blow ins from outside the ROW, is a violation. A few issues with this: How would we "prove" that an outage is vegetation related or not, and if vegetation related, where the vegetation came from? Would this be a "guilty until proven innocent" paradigm, e.g., if we don't know what the cause was, then we assume guilty, or an "innocent until proven guilty" paradigm, e.g., clear evidence is needed to prove guilt? Current compliance monitoring and enforcement methods are to assume guilt with the need for clear evidence of innocence until a hearing is requested, at which point the paradigm is reversed. If this is how we expect it to happen? I could see a large number of "Possible" and "Alleged" violations where the cause of the sustained outage or the source of the vegetation is unknown, and a large number of hearings, unless we begin with the paradigm with "innocent until proven guilty", which is not the approach monitoring and enforcement take currently. The requirement and the measures do not match. The requirement is to "manage". Sometimes a well managed environment can still fail. The measures are "failures". If the measures are failures and any failure is a violation, then, the requirement should be to "prevent" not to "manage". Staff's proposed VSLs highlight this inconsistency. The 100% compliance requirement, as opposed to a statistical measure such as 99.99% availability, and Measures that say that any Sustained Outage is a possible violation unless proven otherwise leads us to extreme methods of management, such as possibly having video cameras monitoring the ROW at all times. Is this what the Drafting Team intends? FMPA would suggest that if perfromance is the real purpose of these standards, then "manage" is the wrong requirement, and "prevent" is a more appropriate term. If prevention is the real requirement, then we need a paradigm of "innocent until proven guilty" and any unknown source of a sustatined outage is assumed not to be a vioaltion until proven guilty, and, 100% is not a reasonable target, 99.99% or similar umber over a number of years (e.g., so many years rolling average) is a more reasonable target. Do we require 100% compliance with vehicle brakes (ala Toyota Prius)? Or tire blowouts (ala Ford Explorer)? With associated fines? If we did, the auto manufacturers would probably not offer cars to the American market due to too much risk and liability. TQM (total

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				qulaity management) processes, such as six sigma (i.e., 6 standard deviations) do not mandate 100% reliability becuase 100% reliability is too expensive. Rather, we need a conservative target where outliers beyond regional management controls do not result in huge fines and huge liability (especially in consideration with FERC's proposed Policy Statement on Sanctions) R4 "Each Transmission Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated transmission line when qualified personnel confirm the existence of a vegetation condition that is likely to cause a Fault at any moment" How is R4 even measureble? How are we to measure how someone would determine "the existence of a vegetation condition that is likely to cause a Fault at any moment"? Having the requirement in the standard may have the unintended consequence of reverse psychology e,g., not notifying may not even open up the question of compliance with this requirement. However, if a sustained outage were to occur as a result violating R1 or R2, would this requirement necessitate launching an investigation of whether or not "qualified" personnel would have seen a problem. I see this requirement as fraught with difficulties. Would this requirement essentially require a procedure for "detecting" in R3 in addition to "preventing" If 100% compliance is the chosen method for R1 and R2, why is R4 (and R5 for that matter) even needed? Obviously, if there is an impending failure that would cause a vioaltion of R1 and R2, then there is obviously incentive to report it to the System Operator. R7 "Each Transmission Owner shall complete the work in an annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk of a vegetation encroachment. Examples of reasons for modification to annual plan may include ...." The first sentence should not include the phrase "to ensure no vegetation encroachments occur" since the requirement is to do the work in the work plan. The added phrase sinply adds ambiguity, e.g., if there is an encroashment, is R7 violated since it does not meet hte "unsure" phrase in addition to R1 and R2? Periodic Data Submittals Due to R1 and R2, this is really a self-certification process because essentially only violations to R1 and R2 as curently drafted would be reported. So, this section should be deleted in favor of a CMEP process for periodic self-certifications on the standard.

Response: Thank you for your comments. Based on recommendations, the language in M1/M2 has been modified. Proof that an outage was vegetation related will be determined through the investigation of the outage. If clear evidence as determined by the Transmission Owner exists, the entity would then self-report. R4 exists to ensure that "expeditious communication between the Transmission Owner **and proper operating personnel when a critical situation is confirmed." This situation does not necessarily imply a violation of R1 and R2. The intent is to minimize the risk of an event that could cause a cascading event. Regarding the inclusion of the phrase "to ensure no vegetation encroachments occur" in R7, the intent of the SDT is to include language to indicate who should do what when, where, and why as part of the Results Based Standards format.**

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Silvia P Mitchell	Florida Power & Light Co.	6	Negative	NextEra Energy, Inc believes that this standard is a step in the right direction; however, it is not ready for ballot. The posted version uses the Measures and Compliance sections to define and interpret Requirements. The Requirements should stand by themselves. This version of the standard lumps grow-in violations with fall-in and blow-in violations. Fall-in and grow-in violations have no correlation to the cascading events stated in the purpose. We believe it needs more work before ballot approval.
Response: The SDT thanks you for your comment. The SDT modified R1 and R2 to incorporate the severity into the requirement. This will allow for a graded VSL. The team also modified the measure so that it does not qualify the requirement. These changes should resolve your issues.				
Larry E Watt	Lakeland Electric	1	Negative	o The draft standard requires perfection, which is an unreasonable performance metric o The standard is prone to arguments of whether or not an outage was caused by vegetation encroachment in the current "guilty until proven innocent" paradigm we are currently in o Are the requirements measurable (e.g., R4 and R5)? o Goals of requirements should not be mixed with the requirement itself. Goals add ambiguity of what is being measured, the requirement (e.g., "complete the work plan" in R7) or the goal (e.g., "ensure no vegetation encroachment occurs"). o Periodic data submittals as written are really periodic self-certifications and ought to be named such, or 100% compliance reduced to a more reasonable target
Response: The SDT thanks you for your comments. The SDT recognizes that the Standard as written is zero tolerance and believes it is compelled to write it that way. FERC staff and NERC assert that a revised standard cannot result in less reliability than the one it replaces, and, their belief is the current Standard is zero tolerance. The SDT believes that R4 and R5 are measurable as described. The RBS process is essentially “Who should perform What actions under What conditions.” Thus the Goals are included. Finally, FERC would prefer to have early warnings that reliability is at risk, rather than wait for that indication when the next blackout occurs. Hopefully, periodic data offers that early warning detection.				
David H. Boguslawski	Northeast Utilities	1	Negative	Our main issue is with the change in the Active ROW definition. The recent addition of a centerline distance to edge of Active ROW is not acceptable as it does not take into consideration the construction of the line (e.g., mono-pole vs. H-frame). For mono-pole construction, the use of the Table 3 centerline distance could result in additional clearing of the forested edge on existing ROWs with no value added to system reliability. Instead of using the term "Centerline" as referenced on Table 3, the use of "outer phase" or "phase closest to tree line" would be more appropriate.
Response: The SDT thanks you for your response. Due to many commenters having issues with trying to define a “minimum” width, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.				
Mace Hunter	Lakeland Electric	3	Negative	Perfection is not a reasionable performance metric
Response: The SDT thanks you for your comment. The SDT recognizes that the Standard as written is zero tolerance and believes it is compelled to				

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write it that way. FERC staff and NERC assert that a revised standard cannot result in less reliability than the one it replaces, and, their belief is the current Standard is zero tolerance.				
Brenda L Truhe	PPL Electric Utilities Corp.	1	Negative	Please refer to the Comments submitted by Earl Burnside, PPL Electric Utilities, via the NERC Comment Form on 7/16/2010.
Response: See responses to Earl Burnside, PPL Electric Utilities.				
Mark A. Heimbach	PPL Generation LLC	5	Negative	Please refer to the comments submitted by Earl Burnside, PPL Electric Utilities, on 7/16/10.
Response: See responses to Earl Burnside, PPL Electric Utilities.				
John C. Collins	Platte River Power Authority	1	Negative	PRPA appreciates the SDT's reliability objective through a defense-in-depth strategy and the improvements made to the standard since its last posting. However, several issues will cause us to vote negative. Our first concern is that a violation caused by an encroachment into the Minimum Vegetation Clearance Distance as shown in Table 2, observed in real time, absent a Sustained Outage does not improve reliability of the BES. Instead we believe the clearances to be achieved in the current version of the standard under R1.2. are a better measurement of expectations because they establish a clearance to be achieved at the time of work. Our next concern is with the ambiguity of the wording "without any intentional time delay" in R4 of the proposed standard. For instance, would a call from the lineworkers to his/her supervisor prior to a call to the control center constitute an intentional delay or would that be part of the confirmation process? We also question what constitutes qualified personnel in R4. Does this imply that R1.3. in the current standard requiring appropriate qualifications and training is still applicable although not implicated stated and will those qualifications be audited as they are now? Our last concern is that landowners will intentionally constrain and delay work through court orders pointing to our Federal requirement to take corrective action. We know this isn't the intent of the requirement but have some concern that it might be misinterpreted by landowners as their defense to force us to investigate or perform alternate work methodology.
Terry L Baker	Platte River Power Authority	3	Negative	
Response: Thank you for your comments. While the SDT has struggled with the issue of encroachments into the MVCD being a violation, the fact that a TO would allow vegetation to approach, let alone encroach the MVCD indicates a serious flaw in the TO's vegetation management program and its application. The TO has every right and should under the proposed standard establish clearance distances at the time of work (Clearance 1 in FAC-003-1) to allow for growth. With regard to Clearance 1 of version 1 the SDT considered it a "fill in the blank" requirement. Thus, including it in version 2 was considered prescriptive and unnecessary. **The time required by the TO to report an issue is subject to many variables such as available communication for the area which could be a hike-in location with no radio or cell phone coverage. For this reason it is difficult to establish a time period which would fairly apply to all TO's. Thus, the SDT has taken the approach which does create some subjectivity. With regard to your question regarding a call from a line worker to a supervisor being viewed as intentional delay, we would need to know if this call is part of your process for reporting imminent threats. If your process has this**				

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check point or the flexibility for the lone worker to call a supervisor, then the SDT would not view this as an intentional delay. **Qualified personnel is a function of many variables such as the size of the TO's system, type and density of vegetation, access and complexity of the vegetation management program. All these factors will drive the qualification requirements as defined by the TO for personnel developing and administering the program. For instance a TO with little vegetation on its ROW may require little in the way of knowledge and methodologies in meeting this standard while those TO's with extensive and significant vegetation must use varied methodologies to control vegetation on its ROW such as mechanical control, manual control, herbicides and so on. Thus, the standard leaves it to the TO to define what defines qualified personnel. Refer to the reference document for more guidance.** **As you point out, it is not the intent of this standard to cause the landowner to intentionally constrain and delay work. But, it is also not the intent of the standard to drive the land owner or land manager to any other behaviors. It is the TO's responsibility to manage relationships and develop methodologies within and to the full extent of the easement or permit language. Requirement R5 deals with this issue and additional clarification is given in the Rationale for this requirement.**				
David Schumann	Florida Municipal Power Agency	5	Negative	R1 & R2 My biggest problem is with R1 and R2 "Each Transmission Owner shall manage vegetation to prevent encroachment that could result in a Sustained Outage of applicable lines .... Types of encroachment include: 1. An encroachment into the Minimum Vegetation Clearance Distance (MVCD) as shown in Table 2, observed in real time, absent a Sustained Outage, 2. An encroachment due to a fall-in from inside the active transmission line ROW that caused a vegetation-related Sustained Outage, 3. An encroachment due to blowing together of applicable lines and vegetation located inside the active transmission line ROW that caused a vegetation-related Sustained Outage, 4. An encroachment due to a grow-in that caused a vegetation-related Sustained Outage" One fundamental problem with all the standards is the demand for no faults, no errors, 100% compliance. Requirements 1 and 2 basically say that any vegetation related outage, except for blow ins from outside the ROW, is a violation. A few issues with this: How would we "prove" that an outage is vegetation related or not, and if vegetation related, where the vegetation came from? Would this be a "guilty until proven innocent" paradigm, e.g., if we don't know what the cause was, then we assume guilty, or an "innocent until proven guilty" paradigm, e.g., clear evidence is needed to prove guilt? Current compliance monitoring and enforcement methods are to assume guilt with the need for clear evidence of innocence until a hearing is requested, at which point the paradigm is reversed. If this is how we expect it to happen? I could see a large number of "Possible" and "Alleged" violations where the cause of the sustained outage or the source of the vegetation is unknown, and a large number of hearings, unless we begin with the paradigm with "innocent until proven guilty", which is not the approach monitoring and enforcement take currently. The requirement and the measures do not match. The requirement is to "manage". Sometimes a well managed environment can still fail. The measures are "failures". If the measures are failures and any failure is a violation, then, the requirement should be to "prevent" not to "manage". Staff's proposed VSLs highlight this inconsistency. The 100% compliance requirement, as opposed to a statistical measure such

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				as 99.99% availability, and Measures that say that any Sustained Outage is a possible violation unless proven otherwise leads us to extreme methods of management, such as possibly having video cameras monitoring the ROW at all times. Is this what the Drafting Team intends? FMPA would suggest that if perfromance is the real purpose of these standards, then "manage" is the wrong requirement, and "prevent" is a more appropriate term. If prevention is the real requirement, then we need a paradigm of "innocent until proven guilty" and any unknown source of a sustatined outage is assumed not to be a vioaltion until proven guilty, and, 100% is not a reasonable target, 99.99% or similar umber over a number of years (e.g., so many years rolling average) is a more reasonable target. Do we require 100% compliance with vehicle brakes (ala Toyota Prius)? Or tire blowouts (ala Ford Explorer)? With associated fines? If we did, the auto manufacturers would probably not offer cars to the American market due to too much risk and liability. TQM (total qulaity management) processes, such as six sigma (i.e., 6 standard deviations) do not mandate 100% reliability becuase 100% reliability is too expensive. Rather, we need a conservative target where outliers beyond regional management controls do not result in huge fines and huge liability (especially in consideration with FERC's proposed Policy Statement on Sanctions) R4 "Each Transmission Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated transmission line when qualified personnel confirm the existence of a vegetation condition that is likely to cause a Fault at any moment" How is R4 even measureble? How are we to measure how someone would determine "the existence of a vegetation condition that is likely to cause a Fault at any moment"? Having the requirement in the standard may have the unintended consequence of reverse psychology e,g., not notifying may not even open up the question of compliance with this requirement. However, if a sustained outage were to occur as a result violating R1 or R2, would this requirement necessitate launching an investigation of whether or not "qualified" personnel would have seen a problem. I see this requirement as fraught with difficulties. Would this requirement essentially require a procedure for "detecting" in R3 in addition to "preventing" If 100% compliance is the chosen method for R1 and R2, why is R4 (and R5 for that matter) even needed? Obviously, if there is an impending failure that would cause a vioaltion of R1 and R2, then there is obviously incentive to report it to the System Operator. R7 "Each Transmission Owner shall complete the work in an annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk of a vegetation encroachment. Examples of reasons for modification to annual plan may include ...." The first sentence should not include the phrase "to ensure no vegetation encroachments occur" since the requirement is to do the work in the work plan. The added phrase sinply adds ambiguity, e.g., if there is an

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<tr><td colspan="5">Response: Thank you for your comments. Your concern with respect to the cause of an outage is well-taken. As you know, transmission systems are subject to many different influences which can cause a sustained outage. Among those causes is the encroachment of vegetation into the MVCD which could be due to improper maintenance of vegetation on one’s ROW. However, there are many other causes which can initiate a sustained outage. A TO usually investigate a sustained outage in the field to determine, if possible, the cause of the outage. Typically, a vegetation caused outage will leave some evidence of the flashover such as burn marks on the conductor together with burned portions of the vegetation. Indications may be found to explain the outage due to other causes but in some cases the cause cannot be determined and the line is successfully re-energized without ever knowing what caused the outage. It is incumbent upon the TO to self- report those outages obviously caused by vegetation but unexplained outages would not fall under this requirement or standard.

The SDT believes the language in the requirement matches the language in the measure such as in R1 “Each Transmission Owner shall manage vegetation to prevent encroachment…” and in M1 “Each Transmission Owner has evidence that it managed vegetation to prevent encroachment…”. Your suggestion of using statistical analysis may work well with large TO’s with many miles of transmission ROW to spread small numbers of outages over but would disadvantage the small TO with significantly fewer miles of line. Only one outage on its system could result in huge fines.

The SDT believes R4 is a valid “Risk Based Requirement” giving guidance to industry on what to do upon discovery of an encroachment into the MVCD in order to prevent a sustained outage. The key is for the TO to communicate with the appropriate switching authority and the measure is evidence of such communication when a potential vegetation imminent threat occurs. R7, as documented in the Rationale, “…sets the expectation that the work identified in the annual work plan will be completed as planned”. Documentation of the work completed (and any necessary modifications) as written together with the lack of of a violation to either Requirement 1 or Requirement 2 is the overall reliability goal. The metric for the work plan is the percentage of the plan complete. The lack of a violation of R1 or R2 is the outcome of the ideal work plan. It is the responsibility of the TO to manage the quality of the work plan and its associated modifications to mitigate the risk of a violation of R1 or R2. With Version 2, an outage is now clearly a violation of R1 and R2 and should not be linked to a failure of the work plan. The measure for the work plan is the percentage of the completed as planned and we do not need to be subjectively trying to evaluate the quality of the TOs plan with this measure. With regard to the “Periodic Reporting Data Submittal” section the SDT agrees with reporting outage to the Regional Entity on a quarterly basis. In addition regulatory authorities are looking for leading reliability indicators which will support quarterly reporting rather than an annual self-certification.</td></tr>
<tr><td>Kenneth Simmons</td><td>Gainesville Regional Utilities</td><td>3</td><td>Negative</td><td>R4 The use of intentional time delay is a qualitative attribute and not a quantitative measure. How does one judge intentional versus non-intentional on a qualitative basis; subjective at best leading to many arguments between auditor and auditee?</td></tr>
<tr><td colspan="5">Response: Thank you for your comment. We agree the time required by the TO to report an issue is subject to many variables such as available communication for the area which could be a hike-in location with no radio or cell phone coverage. For this reason it is difficult to establish a time period which would fairly apply to all TO’s. Thus, the SDT has taken the approach which does create some subjectivity. The key is for the TO to have an imminent threat process that includes the communication with the appropriate switching authority. The measure for compliance will be evidence such as written and taped radio/telephone logs maintained by the control center; written daily diaries kept by the patrollers and inspectors could also be used for this purpose.</td></tr>
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Luther E. Fair	Gainesville Regional Utilities	1	Negative	R4: The use of intentional time delay is a qualitative attribute and not a quantitative measure. It will lead to endless arguments over intentional versus non-intentional. R4 should be: Each Transmission Owner shall notify the control center holding switching authority for the associated transmission line no more than 6 hours of a qualified personnel confirm the existence of a vegetation condition that is likely to cause a Fault at any moment. R7: R7, as proposed, requires a VMP to be completed to ensure no encroachment occurs. The Supplemental Reference for R7 does not describe the requirement of the annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. The Reference states the requirement is established to diminish the risk of encroachment; very different from ensuring no encroachment. In the reference for R7 the word “ensure” is only used to describe that flexibility in the VMP is allowed to ensure the reliability of the Transmission System. The above comments are from United Illuminating and shared by myself. Earl
Response: Thank you for your comments. We agree the time required by the TO to report an issue is subject to many variables such as available communication for the area which could be a hike-in location with no radio or cell phone coverage. For this reason it is difficult to establish a time period which would fairly apply to all TO’s. Thus, the SDT has taken the approach which does create some subjectivity. The key is for the TO to have a imminent threat process that includes the communication with the appropriate switching authority. The measure for compliance will be evidence such as written and taped radio/telephone logs maintained by the control center; written daily diaries kept by the patrollers and inspectors could also be used for this purpose. **R7, as documented in the Rationale, “…sets the expectation that the work identified in the annual work plan will be compiled as planned”. Documentation of the work completed (and any necessary modifications) as written together with the lack of of a violation to either Requirement 1 or Requirement 2 is the overall reliability goal. The metric for the work plan is the percentage of the plan complete. The lack of a violation of R1 or R2 is the outcome of the ideal work plan. It is the responsibility of the TO to manage the quality of the work plan and its associated modifications to mitigate the risk of a violation of R1 or R2. With Version 2, an outage is now clearly a violation of R1 and R2 and should not be linked to a failure of the work plan. The measure for the work plan is the percentage of the completed as planned and we do not need to be subjectively trying to evaluate the quality of the TOs plan with this measure.**				
David A. Lapinski	Consumers Energy	3	Negative	Table 3 does not adequately address ROW width requirements based on the type of construction used for structures, especially for the two lower voltage classes, 69-138kV and

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David Frank Ronk	Consumers Energy	4	Negative	139-230 kV. Lines constructed on H-Frame structures have a much wider footprint across the ROW than do single pole construction and most steel tower construction types. The minimum ROW width listed in Table 3 for a 138 kV line constructed on a wooden H-Frame may put the outside conductor within MVCD under windy conditions due to wind displacement of conductors and trees. Consumers Energy recommends that Table 3 be modified to describe the minimum distance in the table is the vertical plane of the outside conductor to the edge of the active transmission ROW and therefore independent of the width of the structure construction type. MI and M2 fail to provide examples of acceptable forms of evidence to prove that a Transmission Owner actively managed vegetation to prevent encroachment into the MVCD. The Measures should require proof of active ROW clearing activity in accordance with the transmission vegetation management plan, such as invoicing or crew field reports or vegetation inspection data from the annual vegetation inspection R3 avoids defining a minimum clearance specification and is not practical. As written, this would require each Transmission Owner to define and document the procedures, processes or specification by individual span for every line owned or operated by the Transmission Owner. Each span varies in length and profile and a single line may have several different conductor types with different load ratings. Line loadings will vary along the line based on substation taps, etc. The dynamics described in the language could only be done on an individual span basis to be reasonably accurate. This is not practical from a planning standpoint or from a standpoint of implementing clearing work in the field.
Response: The SDT thanks you for your comments. **1) Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.** **2) M1 and M2 do provide samples of acceptable forms of evidence. The examples you have provided in your comment would also be acceptable forms of evidence. The SDT recognizes that there are many acceptable forms of evidence and only included three specific examples in both Measures M1 and M2 utilizing the phrase 'may include' so that the list is not limited to the samples provided.** **R3 specifically states that the TO shall prevent encroachment into the MVCD which is a defined minimum clearance distance, contrary to your comment. To prevent a Sustained Outage, each TO must recognize that each transmission line is unique and establish a general plan that encompasses each scenario. In their procedures or processes or specifications, the TO shall establish a maintenance strategy that ensures vegetation will never violate the MVCD. This strategy should take into consideration the dynamics of vegetation growth and conductor movement as explained in the Guidelines and Technical Basis section of the Standard (Page 21). This strategy does not necessarily require a span by span analysis.**				
Bernard Pelletier	Hydro-Quebec TransEnergie	1	Negative	Table 3 is not acceptable for HQTE. In many places, our standard of design allow us a ROW width much narrower. We think that Table 3 should cover only the lines operated at 200 kV or higher. Finally, the Table 3 should not be a requirement of the FAC-003-2.
Response: Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.				

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<tr><td>Stan T. Rzad</td><td>Keys Energy Services</td><td>1</td><td>Negative</td><td>The draft standard requires perfection, which is an unreasonable performance metric The standard is prone to arguments of whether or not an outage was caused by vegetation encroachment in the current "guilty until proven innocent" paradigm we are currently in Are the requirements measurable (e.g., R4 and R5)? Goals of requirements should not be mixed with the requirement itself. Goals add ambiguity of what is being measured, the requirement (e.g., "complete the work plan" in R7) or the goal (e.g., "ensure no vegetation encroachment occurs"). Periodic data submittals as written are really periodic self-certifications and ought to be named such, or 100% compliance reduced to a more reasonable target</td></tr>
<tr><td colspan="5">Response: The SDT thanks you for your comments.
1. The SDT recognizes that the Standard as written is zero tolerance and believes it is compelled to write it that way because FERC staff and NERC assert that a revised standard cannot result in less reliability than the one it replaces and their belief is the current Standard is zero tolerance.
2. As explained in M1 and M2, only real time observations confirmed by a qualified person would constitute an encroachment. There may be some difficulty proving whether or not an outage was caused by vegetation but, if an investigation at any time reveals definitive evidence of a vegetation contact as determined by the Transmission Owner, this would be the proof.
3. The SDT believes that R4 and R5 are measurable as described in the Draft but would gladly accept suggestions for revision in future postings. The RBS process essentially is “Who should do what, under what conditions, when, and why?” Thus the Goals are included. Finally, FERC staff has stated that they would prefer to have early warnings that reliability is at risk rather than wait for that indication when the next blackout occurs. Thus, periodic data offers that early warning detection.
Periodic data submittal is not only restricted to self-certifications so the SDT has chosen to keep the language the same as currently drafted.</td></tr>
<tr><td>Thomas W. Richards</td><td>Fort Pierce Utilities Authority</td><td>4</td><td>Negative</td><td>The draft standard requires perfection, which is an unreasonable performance metric. Also, the standard is prone to arguments of whether or not an outage was caused by vegetation encroachment in the current "guilty until proven innocent" paradigm we are currently in. I have the question about the ability to measure compliance with R4 and R5 as written. Goals of requirements should not be mixed with the requirement itself. Goals add ambiguity of what is being measured, the requirement (e.g., "complete the work plan" in R7) or the goal (e.g., "ensure no vegetation encroachment occurs"). Periodic data submittals as written are really periodic self-certifications and ought to be named such, or 100% compliance reduced to a more reasonable target</td></tr>
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Voter	Entity	Segment	Vote	Comment
some difficulty proving whether or not an outage was caused by vegetation but, if an investigation at any time reveals definitive evidence of a vegetation contact as determined by the Transmission Owner, this would be the proof. 3. The SDT believes that R4 and R5 are measurable as described in the Draft but would gladly accept suggestions for revision in future postings. The RBS process essentially is "Who should do what, under what conditions, when, and why?" Thus the Goals are included. Finally, FERC staff has stated that they would prefer to have early warnings that reliability is at risk rather than wait for that indication when the next blackout occurs. Thus, periodic data offers that early warning detection. 4. Periodic data submittal is not only restricted to self-certifications so the SDT has chosen to keep the language the same as currently drafted.				
Thomas E Washburn	Florida Municipal Power Pool	6	Negative	The draft standard requires perfection, which is an unreasonable performance metric The standard is prone to arguments of whether or not an outage was caused by vegetation encroachment in the current "guilty until proven innocent" paradigm we are currently in Are the requirements measurable (e.g., R4 and R5)? Goals of requirements should not be mixed with the requirement itself. Goals add ambiguity of what is being measured, the requirement (e.g., "complete the work plan" in R7) or the goal (e.g., "ensure no vegetation encroachment occurs"). Periodic data submittals as written are really periodic self-certifications and ought to be named such, or 100% compliance reduced to a more reasonable target
Response: The SDT thanks you for your comments. 1. The SDT recognizes that the Standard as written is zero tolerance and believes it is compelled to write it that way because FERC staff and NERC assert that a revised standard cannot result in less reliability than the one it replaces and their belief is the current Standard is zero tolerance. 2. As explained in M1 and M2, only real time observations confirmed by a qualified person would constitute an encroachment. There may be some difficulty proving whether or not an outage was caused by vegetation but, if an investigation at any time reveals definitive evidence of a vegetation contact as determined by the Transmission Owner, this would be the proof. 3. The SDT believes that R4 and R5 are measurable as described in the Draft but would gladly accept suggestions for revision in future postings. The RBS process essentially is "Who should do what, under what conditions, when, and why?" Thus the Goals are included. Finally, FERC staff has stated that they would prefer to have early warnings that reliability is at risk rather than wait for that indication when the next blackout occurs. Thus, periodic data offers that early warning detection. 4. Periodic data submittal is not only restricted to self-certifications so the SDT has chosen to keep the language the same as currently drafted.				
Laurie Williams	Public Service Company of New Mexico	1	Negative	The draft standard suggests that the expectation for compliance is perfection or zero encroachments at all times. It would be cost prohibitive to maintain the system under those rules and should be amended to include a provision to account this issue - particularly for small utilities that operate over very large geographic region with sparsely distributed

Voter	Entity	Segment	Vote	Comment
				transmission assets.
Response: The SDT thanks you for your comments. The SDT recognizes that the Standard as written is zero tolerance and believes it is compelled to write it that way because FERC staff and NERC assert that a revised standard cannot result in less reliability than the one it replaces and their belief is the current Standard is zero tolerance.				
Matt Culverhouse	City of Bartow, Florida	3	Negative	The proposed standard requires perfection which we feel is unreasonable.
Response: The SDT thanks you for your comments. The SDT recognizes that the Standard as written is zero tolerance and believes it is compelled to write it that way because FERC staff and NERC assert that a revised standard cannot result in less reliability than the one it replaces and their belief is the current Standard is zero tolerance.				
Robert D Smith	Arizona Public Service Co.	1	Negative	The reasons for APS to vote NO. The standard drafting team went above and beyond and changed the whole standard and didn't address all of FERC's concerns. (0) The minimum clearances must be sufficient to avoid any sustained vegetation-related outages for all applicable conditions. (1) The team eliminated clearance 1 requirement which isn't addressed in this revision according to FERC's request. FERC wanted this requirement to be standardized. Elimination of clearance 1 doesn't give utilities leverage when dealing with federal land agencies. They are making decisions without any education or knowledge on UVM activities which affect transmission reliability. There needs to be a clearance 1 requirement in the standard. If utilities are required to follow this standard it gives them leverage with dealing with these federal land agencies. (2) They removed ANSI-A300 from the standard. It was a footnote but should be part of the standard. Utilities should be held to following ANSI A-300 standards and BMP's for best management practices. By following these standards there wouldn't be a need for the FAC-003 standard. (3) Removal of 'fill in the blank' components where the Transmission Owner determines the requirement with no limits or direction. Examples include and "personnel requirements" in version 1. The SDT removed this requirement from the current version. ? Personnel qualifications should be a requirement. There are certification programs through the International Society of Arboriculture that certify a minimum level of competence to manage a vegetation management program. This also requires ongoing training and education to keep up with the latest technologies on UVM. ? There are other standards that require qualifications and training.

Voter	Entity	Segment	Vote	Comment
				(4) Application of new NERC Drafting Team Guidelines (DTG) to the standard. Examples include the replacement of the current compliance section with Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) as referenced in the Sanction Guidelines. Additionally, documentation and implementation elements are separated into different requirements in the proposed standard as required by the DTG. (5) This requirement in regard to outages from within the ROW was diluted to remove accountability from maintaining the full width of utilities easement. An outage is an outage from a grow-in or from a blow in. If a utility has rights to maintain vegetation there shouldn't be any outages due to vegetation from blowing into the conductors. The active ROW should be wide enough to prevent these types of outages. o Address the applicability and appropriateness of IEEE 516 in determining clearance distances. ? No issues with the change to Gallet equation. ? The issue is each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-Time observations of any MVCD encroachments. ? (6) A real-time observation doesn't take into account all rated conditions and the time the recording was made. Conditions change and if load is increased those previous observations could be potential outages. I would assume our Energy Control people would want to be confident there wouldn't be any tree-related issues if load had to be increased. ? There is technology available with LIDAR to simulate all-rated conditions, contour and tree height to remove these potential trees hazards before an outage occurs. o Address applicability of this standard to sub 200kV lines that could place the grid at an unacceptable risk of instability, separation, or cascading failures. ? (7)The utilities should be required to inspect all the lines annually. The change isn't what FERC requested. o Address applicability to federal lands. ?

Voter	Entity	Segment	Vote	Comment
				(8)There should be a footnote that if federal or state agencies fail to approve annual work plans within 90 days of submittal the utility will not be held accountable for not completing its annual work plan or taking into account the time it takes to get approval. We have land agencies that give us approvals within 2 weeks and others that have taken over a year. Utilities are at their mercy on the approval process. If there is turn-over in the land agency the approval process changes again and it is impossible to determine the anticipated timeline by state, tribal and federal agencies. ? The SDT didn't address the need for FERC oversight on federal lands as the example listed above. Agencies are not qualified to make decisions on utility vegetation management and can change utilities TVMP. (9)Finally the current version FAC-003-1 is performing and there is no need to make the change.

Response: Thank you for your comments.

(0)If vegetation is maintained as required in this draft of the standard in requirements R1 and R2, then no vegetation related sustained outages, caused by vegetation from within the ROW, within the control of the TO can occur.

(1) Clearance 1 was a fill-in the blank requirement and did not provide the TO any new easement rights, or land permit rights across any lands whether those land be privately owned or publicly owned; therefore Clearance 1 remains removed from this draft. Furthermore, the relevance of Clearance 1 depends on several other factors such as length of maintenance cycles, inspection frequency and growth rates. R3 is now used as a more comprehensive method to address these concerns in lieu of a Clearance 1 requirement.

(2) In order to meet the SAR FAC-003 is required. ANSI-A300 is not sufficient to meet the SAR requirements and contains many elements that do not need to be related to transmission system electrical reliability.

(3)The SDT suggests that the submittal of a NERC SAR on the PER standards be considered to address any proposed personnel qualifications, certifications or training issues.

(4) The SDT is following NERC guidelines as they understand them.

(5) The SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way; subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed. Outages arising from vegetation from outside the ROW are not violations of the standard. The SDT had determined this to be the most appropriate assignment of an area of maintenance responsibility considering the numerous variations in easements and permit rights across North America.

(6)The Standard requires the maintenance to be performed such that loading to Rating and Rated Conditions, and the dynamics of sag and sway are are taken into consideration, additionally any real time observations of encroachments into the MVCD are to be reported as violations of the standard. The SDT does not see the need to be prescriptive as to the technology or tools the TO used to be compliant with the Standard, but is confident that if the vegetation in maintained such that no encroachments are ever observed, and no outages are ever occur, then the reliability purpose of the standard will be fully accomplished. Furthermore, the results from a LIDAR survey are temporal in nature. Any program relying on LIDAR would incur a substantial cost with a long term commitment that may not be justified for many Transmission Owners.

(7) FERC requested a defined period for inspection. The SDT agrees with you that annual inspection is required. Therefore the SDT has made annual inspections a Requirement of this Standard. As to all lines versus applicable lines, FERC has accepted the 200 kV bright line for this standard. They did order the SDT to ensure that no sub-200 kV lines that are important to the Bulk Electric System are missing from the Applicability of the standard.

Voter	Entity	Segment	Vote	Comment
The SDT has incorporated a FERC accepted test (as found in the referenced Standard) to make sure no such important lines are missing. **(8)The SDT agrees that erroneous obstacles to compliance with the standard should be addressed. However, they cannot be resolved in this forum, or through language inserted in this standard. This Standard places requirements on the Transmission Owners, not on landowners. There is no legal mechanism for this Standard to take rights from property owners and assign them to the Transmission Owner.** **(9)The SDT is changing the Standard in responds to the SAR. The success of the existing standard will be preserved and enhanced with this revision.**				
Paul Shipps	Lakeland Electric	6	Negative	The standard is prone to arguments of whether or not an outage was caused by vegetation encroachment.
Response: Thank you for your comments. **The Compliance Section of the Standard provides the direction under which the Compliance Monitoring and Enforcement Processes and the TOs must report compliance to this standard. All possible violations need adequate investigation to determine if a vegetation related outage occurred. The SDT recognizes that such determination are often very challenging, however more prescriptive language on investigations has been seen as necessary by the SDT and would not contribute to increased reliability. NERC also requires the TOs to document all outages and their related causes in the TADS system.**				
Daniel Brotzman	Commonwealth Edison Co.	1	Negative	The term “Centerline of the Circuit” in Table 3 is not defined. Until it is defined, there is no way to know if the standard is technically reasonable or whether existing circuits would be in violation of the standard and unable to operate. In addition, it is unclear what types of construction and span lengths were used to develop the distances for active right-of-way widths in Table 3. Furthermore, it is not clear whether Table 3 contains requirements against which compliance will be measured or best practice guidelines. Footnote 2, in the background section, compounds this ambiguity. In short, the lack of a definition for “Centerline” combined with Footnote 2 and Table 3 make this draft unclear and unenforceable. Exelon does not necessarily have easement widths for all transmission lines that equal those defined in Table 3 of this draft; This may require the acquisition of additional easements, if even possible.
Response: Thank you for your comments. **In response to your comments and similar comments to yours, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.**				
Alan Gale	City of Tallahassee	5	Negative	There is still confusion in R7. If I do not complete the work plan, but do not have any encroachments, have I violated R7? As worded I would argue no. I do not believe the ambiguity can remain in the standard. If the goal is to complete the work plan (as modified) leave out the "to ensure no vegetation encroachments..." If the goal is to have no encroachments, do not rely on a work plan to exist. Make the standard "Each TO shall ensure no vegetation encroachments occur." I do agree with the performance based

Voter	Entity	Segment	Vote	Comment
				approach and format.
Response: Thank you for your comments. The SDT considered your response but feels that when one considers all the text in R7, M7, the Rationale and the related VSL, along with the text in the Guidelines and Technical Basis, it is sufficiently clear that this requirement is about the completion of the work plan.				
Roger C Zaklukiewicz		8	Negative	To maintain reliability, the minimum distance from a conductor to tall vegetation should be measured from the conductor nearest the edge of the cleared ROW to the edge of the ROW and not from the center line of the transmission structure. The type of transmission line configuration, horizontal or vertical - monopole versus H-Frame versus lattice-structure versus a V-Guided structure will influence how effective a transmission circuit's performance or reliability is when the measurement is made from the centerline of the transmission line. Table 3 should be modified to reflect this concern to ensure the reliability of the EPS.
Response: In response to your comments and similar comments to yours, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way; subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.				
Brian Evans-Mongeon	Utility Services, Inc.	8	Negative	Utility Services supports the NPCC position on the fixes to this standard proposal.
Response: Thank you for your comments. Please refer to our response to NPCC.				
John K Loftis	Dominion Virginia Power	1	Negative	We do not agree with replacing the term “Active Transmission Line Right of Way” with footnote 2. Our objection is around the distances proposed in Table 3. Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW may not be consistent with the centerline distances cleared and maintained by the TO. For example, a TO maintaining 75’ from centerline for a 500kV circuit would be required to clear and maintain an additional 12.5’ to meet the proposed standard’s requirement. We suggest either allowing individual TOs to maintain active ROW widths consistent with their normal clearing/maintenance practices, going back to Draft 3’s definition of Active Transmission Line Right-of-Way, or changing the footnote in Draft 4 to read: A strip or corridor of land
Michael F Gildea	Dominion Resources Services	3	Negative	
Mike Garton	Dominion Resources, Inc.	5	Negative	

Voter	Entity	Segment	Vote	Comment
Louis S Slade	Dominion Resources, Inc.	6	Negative	that is occupied by active transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities. However, the portion of the ROW that has been cleared must at least meet design clearance requirements such as National Electric Safety Code or other design criteria, for the reliable operation of active facilities.
Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way; subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.				
Ronald L Donahey	Tampa Electric Co.	3	Negative	We have concern with the “Minimum Distances” as listed in Table 3. What analytical methodology, criteria and rationale was utilized to determine each recommended distance? In addition, we have concerns regarding the change to a pre-determined distance. This seems to be a major shift from the vegetation to conductor methodology employed previously and throughout this standard? NERC/FERC must recognize that while protecting and securing grid reliability, each utility must also balance the environmental, political, customer and economic issues and impacts which will occur with the implementation of the Table 3 clearances. We question whether this is the most responsible action to take given the current state of the economy as well as the environmental and political sensitivity impacts which will result. Tampa Electric questions whether Table 3 will improve System reliability. Since the inception of standard FAC-003-1 Tampa Electric has not had a Category 1 or Category 2 outage on our 230kV Transmission System. We don’t believe that the changes proposed to table 3 will improve overall service reliability. It is Tampa Electric’s opinion that each utility should define the width of its own Active Transmission line ROW. However, if such a table is to be utilized, Tampa Electric recommends the following changes or adjustments to Table 3. 1. Expand the table to account for the various types of Transmission construction; i.e. vertical versus horizontal conductor configurations. 2. Use a distance from the outermost conductor, not the centerline. This will account for construction type and better achieve a consistent clearance from conductors. 3. We recommend reducing the distances in Table 3 by 12.5 feet for each voltage category. 4. Specify whether the voltage is based upon the design or operating voltage. 5. Reformat the voltage ranges to 100kV - 200kV, 200kV - 300kV, 300kV - 400kV, etc. as an example; this would create a more appropriate range of voltages and clearance distances. The reformatted voltage ranges eliminate confusion. For example, under the current proposal it is unclear in which category a nominal 230kV line should be since sometimes such a line can operate at up to 232kV during low-load conditions.
Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.				

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Joseph O'Brien	Northern Indiana Public Service Co.	6	Negative	While there are some enhancements to the organization and content of the standard such as the addition of the Guidelines and Technical Basis section, clarification of what constitutes evidence of compliance, and tailoring of VSL severity levels for the requirements based on the risk each poses to the likelihood of contributing to a cascade, too many elements present in FAC-003-1 and which are vital to preventing vegetation caused outages and maximizing system reliability, have been eliminated from FAC-003-2. Specifically, the elimination of concrete, declared and audited clearance standards between vegetation and conductors (the existing Clearance 1 and Clearance 2 (R1.2)) Requirements) in the revised standard is a major defect that will decrease system reliability. It has been indispensable for NIPSCO when communicating with stake holders (governments, interest groups, land owners, the public, etc.) to point to these clearance standards to give credibility and support to the kind of tree removal and trimming that is necessary to achieve the stated objective of zero preventable tree caused outages. Without these declared clearance standards in the NERC standard, utility vegetation managers will constantly be challenged by stake holders to show them that such work is required rather than an elective choice on the utility's part. One of the key lessons learned from the 2003 blackout and First Energy's overgrown ROW tree problem was that individual land owners, local governments, and interest groups will exert pressure on the utility to only do the minimum amount of vegetation management. Without external and enforceable Vegetation Clearance Standards and by returning to a pre-2003 regime where the extent of vegetation clearing is left to the individual discretion and pressures at each utility, there is no doubt that tree clearance conditions will deteriorate over time and put system reliability at greater risk of vegetation contact
Response: The SDT thanks you for your comments. At the request of FERC in Order 693, the SDT was asked to eliminate the fill-in-the-blank clearance requirements that are currently in FAC-003-1. A proven Engineering calculation was utilized to determine when a transmission line could spark over to vegetation without direct contact. Based on this calculation, each utility must determine what clearance levels need to be maintained as part of their TVMP. The current version does not preclude a utility from removing or pruning vegetation well beyond the MVCD, it just establishes a line in the sand that determines when a violation occurs. Individual TOs must establish a program that addresses the many variables that exist such as growth rates, vegetation management cycles, conductor sag and sway, etc. that could result in an encroachment of the MVCD which would be a direct violation of the standard. Establishing a specific clearance value to be attained during vegetation management activities is too prescriptive and is in direct conflict with the Results-Based Standard initiative that the SDT is currently implementing. Each TO must factor in delays and/or mitigation measures associated with stakeholder concerns but must clearly communicate the challenges with maintaining strict compliance with this zero-tolerance standard.				

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td>Greg Lange</td><td>Public Utility District No. 2 of Grant County</td><td>3</td><td>Negative</td><td>While this standard as written is a marked improvement to previous versions, to claim R1 and R2 as results based is simply not right. Had this standard revision not been advertised as the first RBS I probably would have voted yes. Results based by definition should be attained by something either happening or not and should be based on evidence that already exists. If you cause an outage and it is vegetation related then you violate. Why all the words around "managing vegetation encroachment" take care of that in the competency requirements.</td></tr>
<tr><td colspan="5">Response: The SDT thanks you for your comments. In a Results Based Standard, there are three different levels of defense to achieve the desired outcome (performance-based requirements, risk-based requirements and competency based requirements). R1 and R2 are considered Performance-Based requirements and are one component in the defense-in-depth strategy that is described in the Background Section of the current Draft. The MVCD is the minimum clearance distance before a spark-over occurs so R1 and R2 were designed to ensure that the TO manages vegetation appropriately before an outage occurs. If the TO was judged based on outages alone, the defense in depth strategy would fail and, thus, a less reliable standard would exist.</td></tr>
<tr><td>Gregory L Pieper</td><td>Xcel Energy, Inc.</td><td>1</td><td>Negative</td><td rowspan="4">Xcel Energy votes Negative for several reasons which are outlined in the comments submitted to NERC during the comment period that ran concurrently with this ballot. One of the primary objections is the requirement for an annual vegetation inspection. Xcel Energy urges the retention of the provision in the existing standard that allows the Transmission Owner to set the frequency of inspection.</td></tr>
<tr><td>Michael Ibold</td><td>Xcel Energy, Inc.</td><td>3</td><td>Negative</td></tr>
<tr><td>Liam Noailles</td><td>Xcel Energy, Inc.</td><td>5</td><td>Negative</td></tr>
<tr><td>David F. Lemmons</td><td>Xcel Energy, Inc.</td><td>6</td><td>Negative</td></tr>
<tr><td colspan="5">Response: The SDT thanks you for your comments. In FERC Order 693, the SDT was asked to look at setting a specific frequency for vegetation inspections across North America. This was a difficult task since vegetation characteristics vary across the continent but the team voted to accept an annual inspection frequency as a minimum and provide utilities the flexibility to include this mandatory vegetation inspection as part of a general line inspection.</td></tr>
<tr><td>Terry Harbour</td><td>MidAmerican Energy Co.</td><td>1</td><td>Affirmative</td><td rowspan="2">All rationale boxes should have a disclaimer at the top to the effect "For Guidance Only, Not for Enforcement".</td></tr>
<tr><td>Thomas C. Mielnik</td><td>MidAmerican Energy Co.</td><td>3</td><td>Affirmative</td></tr>
<tr><td colspan="5">Response: The SDT thanks you for your affirmative votes and comments. A “disclaimer” is addressed by the Standards Committee Process Subcommittee however its location remains under discussion.</td></tr>
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Guy V. Zito	Northeast Power Coordinating Council, Inc.	10	Affirmative	Although NPCC and its members support the results based initiative and this proof of concept standard and format, there has been some concern with the proposed FAC-003-2. Some of NPCC's members that have active vegetation management programs have stated that in the application of Table 3 - specifically, the use of a "Minimum Distance from the Centerline of the Circuit". Mono-pole and frame construction have significantly different footprints which don't support a one size fits all approach. The use of Table 3 for 345kV, mono-pole construction could result in excessive clearing of additional forested edge on existing ROWs with little if any value added to system reliability and at great cost. There is an issue with use of the term "easements" in the definition and seek clarification on several questions-is there a reason the Active ROW only includes easements not fee ownership, license or some other right to occupy and manage the ROW? Would active ROW include "danger tree rights" on land? Not all entities that own transmission facilities and have vegetation management programs agree with these statements however there is cause enough for concern. In addition, this standard represents a "proof of concept for the "reliability based standards" initiative NERC is putting forward. NPCC RSC believe this initiative will result in better standards over time.
Response: The SDT thanks you for your affirmative vote and comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.				
Jason Shaver	American Transmission Company, LLC	1	Affirmative	ATC raises a concern on including Rationale Boxes plus Guidelines and Technical Basis as part of the NERC Reliability Standard. ATC recommends that the SDT either remove these sections or make them separate from the formal standard to eliminate any risk that these may be construed as requirements. An alternative method is to very clearly identify which parts of the standard are subject to compliance and considered mandatory and which are not considered requirements and are only for guidance in meeting the requirements.
Response: The SDT thanks you for your affirmative vote and comments. A "disclaimer" is addressed by the Standards Committee Process Subcommittee however its location remains under discussion.				
Horace Stephen Williamson	Southern Company Services, Inc.	1	Affirmative	Comments for this ballot are included in the Southern Company submitted comment form - Project 2007-07: Transmission Vegetation Management.
Richard J. Mandes	Alabama Power Company	3	Affirmative	
Anthony L Wilson	Georgia Power Company	3	Affirmative	

Voter	Entity	Segment	Vote	Comment
Gwen S Frazier	Gulf Power Company	3	Affirmative	
Don Horsley	Mississippi Power	3	Affirmative	
Response: The SDT thanks you for your affirmative votes and comments. Please refer to the SDT responses in the Comment Report.				
Ajay Garg	Hydro One Networks, Inc.	1	Affirmative	Hydro One would like to submit the following comments for consideration of the SDT. 1. In the application of Table 3 - specifically, the use of a "Minimum Distance from the Centerline of the Circuit", Mono-pole and frame construction have significantly different footprints which don't support a one size fits all approach. The use of Table 3 for 345kV, mono-pole construction could result in excessive clearing of additional forested edge on existing ROWs with little if any value added to system reliability and at great cost. 2. The use of the term "easements" in the definition needs clarification. For example, is there a reason the Active ROW only includes easements and not ownership, license or some other right to occupy and manage the ROW? Would active ROW include "danger tree rights" on land?
Michael D. Penstone	Hydro One Networks, Inc.	3	Affirmative	
Response: The SDT thanks you for your affirmative vote and comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.				
Richard J. Padilla	Pacific Gas and Electric Company	5	Affirmative	In principle we agree but we have the following concerns: Removes reference to ANSI A300 as an effective management strategy to comply with the standard. We often point to ANSI A300 to support our position of "wire zone - border zone" vegetation management practices in public education and legal disputes. However, Eastern and Southern utilities, who dominate the VMSDT, feel that ANSI A300 places constraints on their desire to perform bare ground clearing, which A300 and PG&E does not endorse. Most Western utilities support retaining reference to A300. Minimum clearance distances have been reduced from the current IEEE 516 distances to the distances derived from the Gallet equation. Reduced clearance distances make it more difficult to justify some work with property owners. FERC and NERC have also stated they are opposed to reduced clearances. The VMSDT spent much time and effort to construct the standard in a manner where there is violation gradation within some requirements. NERC and FERC have indicated they disagree with the latitude to ignore the VSL's as proposed
Response: The SDT thanks you for your affirmative vote and comments. The proposed draft of FAC-003-2 continues to make reference to ANSI A300 as a best practice but short of endorsement into a requirement. This represents the best compromise that the team could achieve. **Use of the Gallet Equation, contrary to your comment, provides for greater distances than IEEE-516-2003 under the same conditions of elevation, voltage and transient overvoltage factor. Please refer to the Technical Reference Document (posted on NERC webpage) for more information.** **The SDT indeed has worked hard to achieve a technically valid set of VSLs for this standard and believe its perspective is correct.**				

Voter	Entity	Segment	Vote	Comment
Steven Grego	MEAG Power	3	Affirmative	MEAG is voting yes in support of the improvements and significant effort that went into modifying FAC-003-2 with the understanding that the vegetation management standard will continue to develop and evolve. Vegetation management's increased visibility and dramatically increased oversight is resulting in increasingly defined and demanding language contained in the standard's requirements. Some of the new requirements overreach but the intent is clear, create and manage a vegetation management program to prevent outages that potentially create a cascading outage threat. As the application of this new standard is reviewed over time, improved requirements and measures based on experience and results should be used to further improve the standard. Additional lines of lesser voltages will now be included under this standard. The tendency may be to include a line when in doubt even if there is a remote possibility that it can potentially cause a threat of a cascading outage. The same philosophy will occur with rights-of-way. The legal right-of-way will be cleared even if it was secured for a future line of greater voltage. We need to continue to review FAC-003-2 for future improvements to achieve reasonableness in protecting against cascading outages without heaping unnecessary costs on electric consumers.
Steven M. Jackson	Municipal Electric Authority of Georgia	3	Affirmative	
Response: The SDT thanks you for your affirmative vote and comments. The SDT agrees with your comments.				
Michael T. Quinn	Oncor Electric Delivery	1	Affirmative	Oncor believes that the proposed standard is a significant improvement over the current standard. We strongly support the suggested VSL's as proposed by the VMSDT. However, we also take the position that adoption of a virtual binary VSL to describe an encroachment without an outage, as a high VSL doesn't adequately address the different levels of encroachment and any potential impact that could lead to Cascading. Oncor is not aware of any vegetation fall-ins or blow-ins that have caused or have lead to Cascading.
Response: The SDT thanks you for your affirmative vote and comments. The SDT has worked hard to achieve a technically valid set of VSLs for this standard and believe its perspective is correct.				
Chifong L. Thomas	Pacific Gas and Electric Company	1	Affirmative	PG&E believes this version is an improvement over the last draft. However, PG&E is concerned with the removal of the reference to ANSI A300 as an effective management strategy to comply with the standard. ANSI A300 provides clarity on the "wire zone - border zone" vegetation management practices. PG&E is also concerned that the minimum clearance distances have been reduced from the current IEEE 516 distances to the distances derived from the Gallet equation. Reduced clearance distances make it more difficult to implement certain types of work needed to support reliability.
Response: The SDT thanks you for your affirmative vote and comments. The proposed draft of FAC-003-2 continues to make reference to ANSI A300 as a best practice but short of endorsement into a requirement. This represents the best compromise that the team could achieve.				

Voter	Entity	Segment	Vote	Comment
Scott M. Helyer	Tenaska, Inc.	5	Affirmative	Please note that further changes may be needed to this standard to address issues related to generation interconnection facilities per other standards development efforts.
Response: The SDT thanks you for your affirmative vote and comments. The SDT is aware that a separate Project 2010-07 Transmission Requirements at the Generator Interface is underway to address the issue you raise.				
Brandy A Dunn	Western Area Power Administration	1	Affirmative	Please see comments provided on Official Comment Form
Response: The SDT thanks you for your affirmative vote and comments. Please refer to the responses in the Comment Report.				
Donald S. Watkins	Bonneville Power Administration	1	Affirmative	Regarding footnote number 2, and the description of an "Active Transmission Line Right of Way", BPA has the following comments: The distance is reasonable in the table, but due to widely varying designs of structures it does not give a relationship of the outside wire to edge of ROW. It should be noted as outside wire, phase or conductor to edge of ROW. In addition, the effective date should allow transmission owners time to achieve this distance, perhaps one cycle. Other Comments: The basis of managing vegetation to MVCD in Table 2 (essentially withstand distances) will likely prove problematic. BPA believes NERC should develop an additional table that calls out minimum "buffers" based on attributes such as line voltage, line rating etc. This table should be a companion to Table 2. It is NERC's responsibility to regulate and we believe that they should do so. In this case, the loss of flexibility for the owners is not necessarily a bad thing.
Rebecca Berdahl	Bonneville Power Administration	3	Affirmative	
Francis J. Halpin	Bonneville Power Administration	5	Affirmative	
Brenda S. Anderson	Bonneville Power Administration	6	Affirmative	
Response: The SDT thanks you for your affirmative votes and comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.				
Tim Kelley	Sacramento Municipal Utility District	1	Affirmative	SMUD appreciates the efforts of the Drafting Team. However, use of the phrase "intentional time delay" in R4 no clear definitive time frame for "intentional time delay" this leads to difficulty in its definition. SMUD respectively offers the recommendation for the DT to use a term along the lines of "expeditious."
James Leigh-Kendall	Sacramento Municipal Utility District	3	Affirmative	
Mike Ramirez	Sacramento Municipal Utility District	4	Affirmative	
Bethany Wright	Sacramento Municipal Utility District	5	Affirmative	
Response: The SDT thanks you for your affirmative votes and comments. The SDT struggled with the selection of language in R4 and considered your term among many others. The team ended up with the drafted version as the best compromise.				

Voter	Entity	Segment	Vote	Comment
Marjorie S. Parsons	Tennessee Valley Authority	6	Affirmative	Suggest a clarifying change to the language in footnote 2 and or Table 3 to address those lines that have ROW width variations from the prevailing width due to factors unrelated to the needs for vegetation maintenance for the subject line. Add the following sentence to footnote 2 "The widths and distances in Table 3 shall be that prevailing width of the ROW exclusive of any variations in the prevailing width due to factors unrelated to the needs for vegetation maintenance for the subject line." TVA asserts that the new language in R1, R2, M1, and M2 in concert with new language in R3 and M3 are fully adequate and superior to any of the proposed alternative A-F. TVA asserts that the VSLs as proposed by the SDT are appropriate since they reflect in various degrees the typical types of right of way maintenance failure. For example vegetation removal from under the conductors should be the highest priority work, followed by vegetation removal in the side-growth/blow-out areas, and lastly of all fall-in risks should be removed. TVA suggests that another sentence be added to the end of Section 4.4 Other, as follows: Nothing is this Standard is shall be used to require the Transmission Owner to acquire additional easement rights beyond those currently owned, or to perform any maintenance outside the limits of its legal rights.
Response: **The SDT thanks you for your affirmative vote and comments. Please see drafting team responses to your same comments in the Comment Report.**				
Paul B. Johnson	American Electric Power	1	Affirmative	The VSL chart states that it is a Lower Violation if the TO has an encroachment into the MVCD observed in real time, absent a sustained outage. While the Moderate and High categories specifically note that the reference is to inside the right-of-way, the Lower level does not. Should the Lower category read: " The Transmission Owner has an encroachment into the MVCD from inside the right-of-way in real time, absent a Sustained Outage"?
Edward P. Cox	AEP Marketing	6	Affirmative	
Response: **The SDT thanks you for your affirmative votes and comments. The suggested edit has been considered and the SDT determined that no change to the VSL would be made.**				
Robert Smith	Duke Energy	5	Affirmative	This Version 2 of FAC-003 takes a big step forward to clarify expectations and compliance with the standard. The results-based format is a big improvement.
Response: **The SDT thanks you for your affirmative vote and comment.**				

Voter	Entity	Segment	Vote	Comment
George T. Ballew	Tennessee Valley Authority	5	Affirmative	TVA suggests a clarifying change to the language in footnote 2 and or Table 3 to address those lines that have ROW width variations from the prevailing width due to factors unrelated to the needs for vegetation maintenance for the subject line. Add the following sentence to footnote 2 “The widths and distances in Table 3 shall be used as the prevailing width of the ROW regardless of any variations in width due to factors unrelated to the needs for vegetation maintenance for the subject line.” TVA asserts that the VSLs as proposed by the SDT are appropriate since they reflect in various degrees the typical types of right of way maintenance failure. For example vegetation removal from under the conductors should be the highest priority work, followed by vegetation removal in the side-growth/blow-out areas, and lastly of all fall-in risks should be removed. TVA suggests that another sentence be added to the end of Section 4.4 Other, as follows: Nothing in this Standard shall be used to require the Transmission Owner to acquire additional easement rights beyond those currently owned, or to perform any maintenance outside the limits of its legal rights.
Response: The SDT thanks you for your affirmative votes and comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed. **The SDT agrees with your comment on the VSLs, and the SDT points out that the following sentence at the end of Section 4.4 is comparable to your suggestion, “Nothing in this section should be construed to limit the Transmission Owner’s right to exercise its full legal rights on the ROW.”**				
Spencer Tacke	Modesto Irrigation District	4	Affirmative	We approve of the proposed revised standard as written. However, we have a concern about the Minimum Vegetation Clearance Distance (MVCD) of 2.97 feet shown in Table 2 for 230kV lines, as being too small. We will continue to maintain a much larger clearance than specified in Table 2, and in this case, no less than 10 feet of clearance for 230kV lines, taking into consideration the maximum sag designed for a given line. Thank you.
Response: The SDT thanks you for your affirmative vote and comments. The MVCD was set up to be a “minimum” distance to never violate. Certainly, each TO must maintain larger clearances in order to account for growth, movement of conductor and other factors that influence the distance between the conductor and vegetation. Use of the Gallet Equation provides for greater distances than IEEE-516-2003 under the same conditions of elevation, voltage and transient overvoltage factor. Please refer to the Technical Reference Document (posted on NERC webpage) for more information.				
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Abstain	Entities have a problem with other Government Agencies in tha they are not real receptive for Vegetation Management. Burea of Land Management will usually take 2 years to get permission to trim vegetation in BLM ROW. State Land Department will usually not let you cut any cactuses in ROW on State land. ROW crossing on a Sovereign Indian Reservation is just as bad. If this is such a big issue for FERC/NERC, then they need to get other governmental agencies on board with them.

Voter	Entity	Segment	Vote	Comment
Response: **The SDT thanks you for your comments. Jurisdictional issues need to be addressed in other appropriate arenas. The Utility Arborist Association among other groups have sought to coordinate cooperation between agencies in the past.**				

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on 4th Draft of FAC-003-2 Transmission Vegetation Management —Project 2007-07 Vegetation Management

The Vegetation Management Standard Drafting Team thanks all commenters who submitted comments on the 4th draft of reliability standard FAC-003-2 — Transmission Vegetation Management. This standard and its associated implementation plan and technical reference paper were posted for a 30-day public comment period from June 17, 2010 through July 17, 2010. The stakeholders were asked to provide feedback on the standard through a special Electronic Comment Form. There were 45 sets of comments, including comments from more than 100 different people from over 50 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

The standard and its associated implementation plan and technical reference paper were balloted from July 9 – 19, 2010. The voting had a quorum of 86.18 percent and an affirmative vote of 65.93 percent. Because at least one negative ballot included a comment and the affirmative votes did not meet the two thirds threshold for approval, the results were not final.

On November 4, 2010, NERC staff provided a Quality Review of FAC-003-2 to the Standards Committee (SC). The SC met on November 11, 2010 to determine if the draft standard should proceed to posting. During the meeting, the SC requested the Vegetation Management Standard Development Team (VMSDT) to work with NERC staff in addressing the items identified in the Quality Review. The VMSDT conducted several conference calls and acted in good faith to produce Draft 5 of FAC-003-2. The VMSDT considered the feedback provided in the Quality Review by NERC staff and reached consensus in the following areas:

1. Elaborated upon the Purpose Statement to encompass more of the standard's content.
2. Added a Rationale text box to the section 4 - Applicability to explain the exclusion of substation facilities. Clarified 4.2.4 by adding specific boundary details.
3. Updated Requirement R1 and R2 to emphasize the "planning" time horizon as the applicable temporal context.
4. Elaborated upon the explanation in the Rationale text boxes for R1 and R2 to highlight the range of non-compliant performance.
5. Re-organized the content of Requirement R3 for improved readability.
6. Augmented Requirement R5 to include a "reliability objective".
7. Modified Requirement R6 and the associated VSLs for improved enforceability and for consistency in the units of measure between the Requirement and the associated VSLs.
8. Modified Requirement R7 and the associated VSLs for improved enforceability and for consistency in the units of measure between the Requirement and the associated VSLs.
9. Updated the Evidence Retention section in accordance with current guidelines.

Modifications incorporated into Draft 5 of FAC-003-2 in response to stakeholder comments include:

A. Removed reference to Active Transmission Line Right of Way (ROW).
B. Redefined the Glossary term for ROW to address Paragraph 734 of FERC Order 693 addressing the width of ROW to be maintained.
C. Redefined the Glossary term for Vegetation Inspection to include identifying hazards to the line inside the ROW.
D. Included the term referred to as "applicable lines" under Section 4.2 Facilities.

E. Removed Section4.4 and footnote 2 addressing "force majeure" and addressed the issue in new footnotes 2, 3 and 4.
F. In R1./R2 – M1/M2
    - Added reference "into the MVCD" (Minimum Vegetation Clearing Distance – MVCD) into the text.
    - Eliminated "types of encroachment" and added "The four types of failure to manage vegetation, in order of increasing severity."
    - In M1/M2, added a paragraph defining "later confirmation of a Fault by the TO as a real-time observation."
    - Added to the Rationale box types of failures to manage vegetation.
G. In R4, changed "qualified personnel" to TO.
H. In R5, added the term "is constrained from performing vegetation work" and referenced MVCD. Also removed reference to the 2003 northeast blackout from Rationale box
I. In R6, added the phrase " but no more than 18 months between inspections." Also added Footnote 3.
J. In R7, replaced major storms bullet with "circumstances that are beyond the control of a Transmission Owner." Also added Footnote 4 to this requirement.
K. In Additional Compliance Information
    - Category 2 was split into two parts recognizing Interconnection Reliability Operating Limits (IROL's) and Major Western Electric Coordinating Council (WECC) Transfer Paths.
    - Added Category 3 for Fall-ins from outside the ROW.
    - Category 4 was split into two parts recognizing IROL's and Major WECC Transfer Paths
L. Removed alternate versions of Violation Severity Levels (VSL's) for Requirements R1 and R2.
M. Deleted Table 3 from the Guidelines and Technical Basis section.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Michael Schiavone	National Grid	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Dean Ellis	Dynegy	NPCC	5
8.	Ben Eng	New York Power Authority	NPCC	4
9.	Brian Evans-Mongeon	Utility Services	NPCC	8
10.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
11.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
12.	Kathleen Goodman	ISO - New England	NPCC	2
13.	Chantel Haswell	FPL Group, Inc.	NPCC	5
14.	David Kiguel	Hydro One Networks Inc.	NPCC	1
15.	Michael R. Lombardi	Northeast Utilities	NPCC	1

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
16. Randy MacDonald			New Brunswick System Operator	NPCC					2				
17. Bruce Metruck			New York Power Authority	NPCC					6				
18. Lee Pedowicz			Northeast Power Coordinating Council	NPCC					10				
19. Robert Pellegrini			The United Illuminating Company	NPCC					1				
2.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				
Additional Member			Additional Organization	Region					Segment Selection				
1. Chuck Sheppard			BPA, Tx Vegetation/Access Road Mgmt	WECC					1				
2. Steve Narolski			BPA, Tx Vegetation/Access Road Mgmt	WECC					1				
3. Vince Ierulli			BPA, Transmission Line Design	WECC					1				
4. Frank Weintraub			BPA, Transmission Line Design	WECC					1				
5. Daniel Tuominen			BPA, Transmission Line Design	WECC					1				
6. Joel Billings			BPA, Transmission Line Design	WECC					1				
7. Michael Staats			BPA, Transmission Engineering	WECC					1				
8. Don Swanson			BPA, Transmission Line Maintenance Technical Svcs	WECC					1				
3.	Group	Sasa Maljukan	Hydro One	X									
Additional Member			Additional Organization	Region					Segment Selection				
1. David kiguel			Hydro One Networks Inc.	NPCC					1				
2. Patrick HOWE			Hydro One Networks Inc.	NPCC					1				
3. Leslie KOCH			Hydro One Networks Inc.	NPCC					1				
4. Jonathan MARRIOTT			Hydro One Networks Inc.	NPCC					1				
4.	Group	Richard Kafka	Pepco Holdings, Inc - Affiliates	X		X		X	X				
Additional Member			Additional Organization	Region					Segment Selection				
1. Pat Byrne			Potomac Electric Power Company	RFC					1				
2. Dave Paduda			Potomac Electric Power Company	RFC					1				
3. Steve Benn			Delmarva Power & Light	RFC					1				
4. Olivia Watts			Atlantic City Electric	RFC					1				
5.	Group	Joseph DePoorter	MRO's NERC Standards Review Subcommittee (nsrs)										X

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	OPPD	MRO	1, 3, 5, 6
2.	Chuck Lawrence	ATC	MRO	1
3.	Tom Webb	WPSC	MRO	3, 4, 5, 6
4.	Jason Marshall	MISO	MRO	2
5.	Jodi Jenson	WAPA	MRO	1, 6
6.	Ken Goldsmith	ALTW	MRO	4
7.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
8.	Eric Ruskamp	LES	MRO	1, 3, 5, 6
9.	Joseph Knight	GRE	MRO	1, 5, 6
10.	Joe DePoorter	MGE	MRO	3, 4, 5, 6
11.	Scott Nickels	RPU	MRO	4
12.	Terry Harbour	MEC	MRO	1, 3, 5, 6
13.	Carol Gerou	MRO	MRO	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Sam Ciccone	FirstEnergy			X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rebecca Spach	FE	RFC	1
2.	Katrina Schnobrich	FE	RFC	1
3.	Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6
4.	Dave Folk	FE	RFC	1, 3, 4, 5, 6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Michael Gammon	Kansas City Power & Light	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jennifer Flandermeyer	KCPL	SPP	1, 3, 5, 6
2.	Duane Ansteate	KCPL	SPP	1, 3, 5, 6
3.	Dean Beasley	KCPL	SPP	1, 3, 5, 6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Mallory Huggins	NERC Staff										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Robert Novembri	NERC	NA - Not Applicable	NA

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
2.	Gerry Adamski		NERC	NA - Not Applicable					NA				
3.	Joel deJesus		NERC	NA - Not Applicable					NA				
4.	Valerie Agnew		NERC	NA - Not Applicable					NA				
5.	Mike DeLaura		NERC	NA - Not Applicable					NA				
6.	Maureen Long		NERC	NA - Not Applicable					NA				
7.	David Taylor		NERC	NA - Not Applicable					NA				
8.	Herb Schrayshuen		NERC	NA - Not Applicable					NA				
9.	Group	Louis Slade	Dominion	X		X		X	X				
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Aaron Jonas			SERC					1				
2.	John Loftis			SERC					3				
3.	Mike Garton								5				
10.	Individual	Brandy A. Dunn	Western Area Power Administration	X									
11.	Individual	Jana Van Ness	Arizona Public Service Company	X		X		X	X				
12.	Individual	Steve Rueckert	Western Electricity Coordinating Council										X
13.	Individual	Luke Diruzza	Tampa Electric Company	X		X		X	X				
14.	Individual	Silvia Parada Mitchell	FPL FPL Corporate Compliance	X				X	X				
15.	Individual	JT Wood	Southern Company Transmission	X		X							
16.	Individual	Linwood Blacksmith	Tri-State Generation & Transmission	X									
17.	Individual	David Burke	Orange and Rockland Utilities, Inc.	X		X							
18.	Individual	Weston Davis	Central Maine Power Company, Iberdrola USA	X									
19.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
20.	Individual	Jonathan Appelbaum	The United Illuminating Company	X									
21.	Individual	Patrick Simons	Idaho Power Company	X									
22.	Individual	Sam Stonerock	Southern California Edison Company	X				X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
23.	Individual	Marty Berland	Progress Energy	X		X		X	X				
24.	Individual	John Bee	Exelon	X		X		X					
25.	Individual	Hugh Conley	Allegheny Power	X									
26.	Individual	Edward Davis	Entergy Services	X		X		X	X				
27.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				
28.	Individual	Gordon Rawlings	BC Hydro	X	X	X		X					
29.	Individual	Bill Rees	BGE Forestry Management	X									
30.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X					
31.	Individual	Bryan Taylor	Idaho Power	X									
32.	Individual	Anne Beard	PNM	X		X							
33.	Individual	James Sharpe	South Carolina and Gas	X		X		X	X				
34.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
35.	Individual	Andrew Z.Pusztai	American Transmission Company	X									
36.	Individual	Terry Harbour	MidAmerican Energy	X									
37.	Individual	Claudiu Cadar	GDS Associates	X									
38.	Individual	Joe Knight	Great River Energy	X		X		X	X				
39.	Individual	Kirit Shah	Ameren	X		X		X	X				
40.	Individual	Earl V. Burnside	PPL Electric Utilities	X		X							
41.	Individual	Jianmei Chai	Consumers Energy Company			X	X	X					
42.	Individual	Michael Pakeltis	CenterPoint Energy	X									
43.	Individual	E Hahn	MWDSC (METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA)	X									
44.	Individual	George Czerniewski	Consolidated Edison Company of New York Inc	X									

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
45.	Individual	James W. Smith	ITC Transmission										

1. The SDT replaced the defined term "Active Transmission Line Right of Way" with footnote number 2 that provides a description of "active transmission line ROW" and added Table 3, "Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW" to support that description. Do you agree? Please explain.

Summary Consideration:

Of 45 respondents, there is 1 abstention, 19 are in agreement, and 25 are in disagreement.

The major comment issues raised are:

1. **The values used in Table 3 needs to be justified.**
2. **The definition of an active transmission line ROW ought to be a Glossary term.**
3. **The Table does not account for different structure designs and the term "centerline" is not applicable in all cases.**

The VM SDT considerations for the major comment issues are:

1. **The VM SDT added explanatory text in the Guideline and Technical Basis section.**
2. **Based on comments from 4th posting the SDT is revising the definition of ROW in the NERC Glossary.**
3. **Table 3 has been removed.**

Some minor comment issues are:

1. **Add distances for DC lines into Table 3.**
2. **The term and Table 3 needs further clarification.**

The VM SDT considerations for the minor comment issues are:

1. **Table 3 has been removed.**
2. **Table 3 has been removed.**

	Organization	Yes or No	Question 1 Comment
1	MWDSC (METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA)		
2	Hydro One	No	A DC table for Table 3 similar to the MVCD table should be added.There should be a statement in Table 3 that is consistent with footnote number 2 stating that the minimum width of the Active Transmission Line ROW is either the full width of the easement or, if the easement is wider than the distances in Table 3, the minimum distances must not be less than the distances shown in the Table. The use of a minimum distance from the centerline of the circuit or structure is an incorrect measure to use for a set clearance distance of the active transmission right-of-way. The description does not take into account vertical versus horizontal design configuration. Consideration should be given for the type of construction as different construction types (H-Frame, Lat-tice towers, Monopole delta or vertical construction) will require different widths of a cleared right-of-way to provide the necessary openings for these circuits. A minimum distance for 345-kV is now set at 150 feet based on the minimum distances from centerline. This may be correct for certain H-Frame and Lattice Tower configurations but it is excessive for monopole situations. A single pole configuration with vertically aligned conductors does not need this full 150 foot width. It is strongly recommended that a minimum distance from conductor be used in place of a set distance from centerline. As long as there is at least 30 - 40 feet of clearance in the right-of-way from the outermost conductors (adjusted to account for maximum sway at mid-span for longer spans), then this is the distance that should be used to develop the right-of-way widths.For example, a monopole structure with vertically aligned conductors would result in a cleared active right-of-way width of only 80 feet (40 feet from conductor to edge of cleared active right-of-way) using the minimum distances from the conductors. There is no need to extend this distance another 35 feet (on each side) in order to obtain the full 150 foot width. This requirement is excessive and must be adjusted to account for line construction variations.

	Organization	Yes or No	Question 1 Comment
			Instead of using the term "Centerline" as referenced on Table 3, the use of "outer phase" or "phase closest to tree line" would be more appropriate. There is published literature using the term "cleared width" to indicate the distance from the outer phase to the tree line. This distance should be used in the Active ROW definition. The word easement is also used in the definition. Is there a reason the Active ROW only includes easements, not fee ownership, license or some other right to occupy and manage the ROW? Would Active ROW include "danger tree rights" on land? These questions need to be addressed in the standard (in text) and technical reference document (in graphics).
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
3	Allegheny Power	No	Allegheny Power strongly disagrees with the numbers or widths stated within Table 3. These numbers seem arbitrary and have no accompanying reasonable explanation as to their origin, basis, or other criteria noting the rationale for inclusion in this standard. This inclusion effectively prohibits a TO from establishing corridor widths less than the widths (which may be easily possible by utilizing various tower or structures heights or configurations) stated in Table 3 without placing the TO in extreme jeopardy of non-compliance issues from a falling off-corridor tree, during minor storm conditions as an example. Furthermore, this Table insinuates the TO has no ability to successfully manage vegetation WITH NO RESULTING OUTAGES or encroachments within the MVCD from off-corridor trees where corridors are less that the widths stated in Table 3.Allegheny Power suggests that the definition of the "Active Transmission line Right Of Way" be "the transmission line ROW corridor that is actively maintained as part of the entity's vegetation management plan.".
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
4	FPL Corporate Compliance	No	Although there is support for making Active Transmission Line Right of Way a clearly defined term, and the foundation for compliance with FAC-003-2, the distances in the table are arbitrary and are not supported by any scientific

	Organization	Yes or No	Question 1 Comment
			or engineering analysis. It is possible that such a table could be interpreted to define the minimum width of future lines. Different construction configurations require different ROW widths.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
5	PPL Electric Utilities	No	Centerline (CL) distances shown in Table 3 are shown as Minimal distances from CL. If utility is not able to define its ultimate ROW, due to CL agreement or other circumstances, these minimal distances may not be applicable and as such could result in non-compliance as written.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
6	Southern Company Transmission	No	Depending on the intent this may create a problem. We are concerned the addition of Table 3 could be interpreted to mean something completely different than what we believe to be its intention. Please consider alternate wording to Footnote 2: A strip or corridor of land that is occupied by active transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities. However, the active transmission line ROW cleared width it is not to be less than the width of the easement itself unless the easement exceeds distances as shown in Table 3 for various voltage classes.If the SDT determines keeping Table 3 is the appropriate course of action, we recommend clarifying its intent better; either in a footnote or in the title. Adding a footnote stating the Table is not applicable if the distance from the center line of the conductor to the right-of-way edge is less than the appropriate distance indicated in the table.Another option might be to add a statement to the title such as, “If the distance from the centerline of the circuit to the edge of the easement is less than the values in Table 3, that distance is considered active ROW”.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way.		

	Organization	Yes or No	Question 1 Comment
	Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
7	Ameren	No	Does this mean wider ROW easements will need to be acquired to be compliant or will this apply to ROW's for new circuits going forward?
	Response: Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
8	Progress Energy	No	In Applicability Section 4.4, "active transmission line ROW" is not capitalized indicating it is not a defined term, but Footnote 2 is effectively a definition for active transmission line ROW. However, in the first paragraph of Section 5 Background, Active Transmission Line Right-of-Way is capitalized indicating it's a defined term. It would seem cleaner to make "Active Transmission Line Right of Way" a formal NERC definition. Alternatively and at a minimum, Footnote 2 should be revised to say "An active transmission line ROW is a strip or corridor..." and also in Section 5 Background, "Active Transmission Line Right of Way" should be changed to no longer be capitalized.
	Response: Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
9	PNM	No	ROW easements vary according to land ownership therefore, potentially subjecting the utility to be liable for land outside of easement/ROW.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
10	Central Maine Power Company, Iberdrola USA	No	Table 3 distances may not be appropriate, for example table 3 should reflect a clearance zone based on construction type, topography, species, or growth rates. Table 3 could give the impression that the listed distances are the maximum, therefore suggest table 3 be removed or revised.The Active Transmisson Line Right-of-Way defination uses the word easement, which most likely would include danger trees in situations where danger removals

	Organization	Yes or No	Question 1 Comment
			are included in the the easement language. This would expand the scope of FAC 003 2 beyond the cleared right-of-way width.
	Response: The SDT agrees that Table 3 does not reflect the structural differences which directly determines the right of way width. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
11	Consumers Energy Company	No	Table 3 does not adequately address ROW width requirements based on the type of construction used for structures, especially for the two lower voltage classes, 69-138kV and 139-230 kV. Lines constructed on H-Frame structures have a much wider footprint across the ROW than do single pole construction and most steel tower construction types. The minimum ROW width listed in Table 3 for a 138 kV line constructed on a wooden H-Frame may put the outside conductor within MVCD under windy conditions due to wind displacement of conductors and trees.Consumers Energy recommends that Table 3 be modified to describe the minimum distance in the table is the vertical plane of the outside conductor to the edge of the active transmission ROW and therefore independent of the width of the structure construction type.
	Response: The SDT agrees that Table 3 does not reflect the structural differences which directly determines the right of way width. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
12	The United Illuminating Company	No	The definition has been altered. The last sentence "However, it is not to be less than the width of the easement itself unless the easement exceeds distances as shown in Table 3 for various voltage classes..." was added. The concept of the easement is confusing and not included in the Supplemental Reference. Table 3 of the standard is titled "Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW", no mention of easements. It is suggested that the definition state "strip or corridor of land that is occupied by active transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities. At a minimum the width is to be the distances as shown in Table 3 for various voltage classes."The

	Organization	Yes or No	Question 1 Comment
			proper location for the definition is in the Glossary.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
13	Dominion	No	The distances proposed in Table 3 - Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW may not be consistent with the centerline distances cleared and maintained by the TO. For example, a TO maintaining 75' from centerline for a 500kV circuit would be required to clear and maintain an additional 12.5' to meet the proposed standard's requirement. We suggest either allowing individual TOs to maintain active ROW widths consistent with their normal clearing/maintenance practices, going back to Draft 3's definition of Active Transmission Line Right-of-Way, or changing the footnote in Draft 4 to read:A strip or corridor of land that is occupied by active transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities. However, the portion of the ROW that has been cleared must at least meet design clearance requirements such as National Electric Safety Code or other design criteria, for the reliable operation of active facilities.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
14	BC Hydro	No	The footnote definition is ok but Table 3 is poorly developed. The voltage classes should be better segregated (e.g. nominal voltage 69kV, 138kV, 230kV, 287kV, 345kV, 500kV, 765kV) along with distances in feet and metres as Canadian utilities are metric. Also the table should include recommended right of way widths for single circuits. The assumption made in the footnote is that the legal easement is larger than in Table 3. However, as currently defined, some of the distances in Table 3 exceed statutory rights of way at our utility and exceed engineering standards as defined by the Canadian Standards Association - Overhead Systems (CAN/CSA C22.3 No. 1-6). Also, clearances will very much depend on line design (e.g. structure architecture such as flat, Post T, H-frame, steel lattice, and other variables

	Organization	Yes or No	Question 1 Comment
			such as ruling span length, conductor type used, etc.) To some degree this will vary quite a bit between utilities. As such Table 3 as currently presented is not workable.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
15	Exelon	No	The term "Centerline of the Circuit" in Table 3 is not defined. Until it is defined, there is no way to know if the standard is technically reasonable or whether existing circuits would be in violation of the standard and unable to operate. In addition, it is unclear what types of construction and span lengths were used to develop the distances for active right-of-way widths in Table 3. Furthermore, it is not clear whether Table 3 contains requirements against which compliance will be measured or best practice guidelines. Footnote 2, in the background section, compounds this ambiguity. In short, the lack of a definition for "Centerline" combined with Footnote 2 and Table 3 make this draft unclear and unenforceable. Exelon does not necessarily have easement widths for all transmission lines that equal those defined in Table 3 of this draft; This may require the acquisition of additional easements, if even possible.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
16	Northeast Utilities	No	The use of a minimum distance from the centerline of the circuit or structure is an incorrect measure to use for a set clearance distance of the active transmission right-of-way. Consideration should be given for the type of construction as different construction types (H-Frame, Lattice towers, Monopole delta or vertical construction) will require different widths of a cleared right-of-way to provide the necessary openings for these circuits. A minimum distance for 345-kV is now set at 150 feet based on the minimum distances from centerline. This may be correct for certain H-Frame and Lattice Tower configurations but it is excessive for monopole situations. A single pole configuration with vertically aligned conductors does not need this full 150 foot width. It is strongly recommended that a minimum distance from

	Organization	Yes or No	Question 1 Comment
			conductor be used in place of a set distance from centerline. As long as there is at least 30 - 40 feet of clearance in the right-of-way from the outermost conductors (adjusted to account for maximum sway at mid-span for longer spans), then this is the distance that should be used to develop the right-of-way widths.For example, a monopole structure with vertically aligned conductors would result in a cleared active right-of-way width of only 80 feet (40 feet from conductor to edge of cleared active right-of-way) using the minimum distances from the conductors. There is no need to extend this distance another 35 feet (on each side) in order to obtain the full 150 foot width. This requirement is excessive and must be adjusted to account for line construction variations.Instead of using the term "Centerline" as referenced on Table 3, the use of "outer phase" or "phase closest to tree line" would be more appropriate.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
17	Idaho Power Company	No	The way I interpret this, the new definition of active transmission line right of way takes away our ability to clear potential fall ins if they are outside of the active transmission line ROW>
	Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
18	CenterPoint Energy	No	There is no rationale provided for the “minimum distances” stated in Table 3, and they far exceed the ROW widths that CenterPoint Energy owns (typical total 100’ ROW width for 2-ckt 345kV line) for its current 345kV system, and as such, are open for misapplication and misinterpretation as an intended minimum standard for making a fall-in determination for R1 and R2 outside the legal limits of the utility. Table 3 should be deleted. If kept, there should be sufficient rationale included within the Guidelines and Technical Basis to explain how it was derived and how it is to be used within the Standard. CenterPoint Energy agrees with the removal of “active transmission line ROW” as a defined term; however, the footnote should be deleted as well since it attempts to create a definition which is not accurate, necessary or

	Organization	Yes or No	Question 1 Comment
			useful. Throughout the Standard, the phrase "active transmission line ROW" should be replaced with "transmission line ROW" to eliminate the qualifying term "active". In making a fall-in determination for R1 and R2, the limit should be "within the full extent of the Transmission Owner's transmission ROW as defined by easement, fee simple, or other legal rights" as discussed in the Guidelines and Technical Basis regarding the vegetation management maintenance approach. This places the determination of the width of the ROW for determination of fall-in violations clearly on the Transmission Owner and the within the limits of its legal rights to control the vegetation that has fallen into the line under R1 and R2.
	Response: The SDT thanks you for your comments. The SDT disagrees with the point that the TO should be required to clear the entire extent of legal rights. FERC Order 693 agreed that expansion easements needed to be adressed. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
19	Northeast Power Coordinating Council	No	There should be a statement in Table 3 that is consistent with footnote number 2 stating that the minimum width of the Active Transmission Line ROW is either the full width of the easement or, if the easement is wider than the distances in Table 3, the minimum distances must not be less than the distances shown in the Table.The use of a minimum distance from the centerline of the circuit or structure is an incorrect measure to use for a set clearance distance of the active transmission right-of-way. The description does not take into account vertical versus horizontal design configuration. Consideration should be given for the type of construction as different construction types (H-Frame, Lattice towers, Monopole delta or vertical construction) will require different widths of a cleared right-of-way to provide the necessary openings for these circuits. A minimum distance for 345-kV is now set at 150 feet based on the minimum distances from centerline. This may be correct for certain H-Frame and Lattice Tower configurations but it is excessive for monopole situations. A single pole configuration with vertically aligned conductors does not need this full 150 foot width. It is strongly recommended that a minimum distance from conductor be used in place of a set distance from centerline. As long as there is at least 30 - 40 feet of clearance in the right-of-way from the outermost conductors (adjusted to account for maximum sway at mid-span for longer spans), then this is the

	Organization	Yes or No	Question 1 Comment
			distance that should be used to develop the right-of-way widths.For example, a monopole structure with vertically aligned conductors would result in a cleared active right-of-way width of only 80 feet (40 feet from conductor to edge of cleared active right-of-way) using the minimum distances from the conductors. There is no need to extend this distance another 35 feet (on each side) in order to obtain the full 150 foot width. This requirement is excessive and must be adjusted to account for line construction variations.Instead of using the term "Centerline" as referenced on Table 3, the use of "outer phase" or "phase closest to tree line" would be more appropriate. There is published literature using the term “cleared width” to indicate the distance from the outer phase to the tree line. This distance should be used in the Active ROW definition. The word easement is also used in the definition. Is there a reason the Active ROW only includes easements, not fee ownership, license or some other right to occupy and manage the ROW? Would Active ROW include “danger tree rights” on land? These questions need to be addressed in the standard (in text) and technical reference document (in graphics).
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
20	Arizona Public Service Company	No	These clearances could exceed the permitted ROW’s on federal lands and the utility has no legal right to clear beyond those rights. In some cases the permitted ROW can exceed those distance and federal agencies could not allow you to clear beyond those clearances in this version.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
21	Entergy Services	No	This is very unclear, and creates much uncertainty as to how certain potential outage situations should be reported. Clarification language should be added within the Standard to help define and guide the TO's actions when an outage occurs from a location at a point that is less than the documented ROW boundaries (Easements) but greater than the ROW distances represented in Table 3. It is unclear which distance should guide our

	Organization	Yes or No	Question 1 Comment
			reporting actions........ROW Document Width, Table 3 ROW Widths, or the lesser of the two.......See scenarios / examples below for consideration to aid with clarification points:Example 1: If our documented ROW width for a 500kV line is 100' from centerline (200' total ROW width) and we have a fall in from 90' from centerline, do we report this as a Category 2 Outage due to the fact that it fell from within our ROW limits, or is it non-reportable due to the fact that it is located at a greater distance than 87.5' from the centerline of the ROW as listed in Table 3 in the Standard?Example 2: How does maintenance and outage reporting correlate with the example defined as follows.......You have a 230 kV line situated on one side of a 150' wide ROW that was initially cleared to a width that would accommodate 2 separate parallel transmission lines and structures. The second set of lines/structures have not yet been constructed, and the current Transmission line is situated on one side of the 150' ROW, and is being maintained to the edge of the actual ROW on the side of the ROW that it was constructed on (maintained to a distance of 50' from centerline that puts it at the legal edge of the ROW), but it has been typically maintained to a distance of approximately 60' from centerline to the inside portion/other side of the ROW (the side of the ROW that has never been cleared), but a tree falls into the line from approx 58' from centerline (2' within the 60' distance typically being maintained on that line).......would this be considered a Category 2 outage since it was approx 2' within the average width being maintained on that side of the ROW or would it not be reported due to the fact that it was located at a distance greater than 50' as indicated in Table 3??
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
22	Kansas City Power & Light	No	This needs to be a defined term since the Standard uses that as a basis for use with Table 3. Using this term as a footnote does not allow the industry to weigh in on its definition. Footnotes should not be used as a means of definition or clarification. Footnotes are for references to other sources of statements or documents that support a particular thought.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way.		

	Organization	Yes or No	Question 1 Comment
	Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
23	Xcel Energy	No	We believe Active Transmission ROW should be a defined term, not buried in a “footnote” of the “Other” section of a Standard. It still begs the question - what is an “active transmission facility”? Regarding the substance, overall we believe that the Active Transmission ROW should not include the new reference to Table 3. This newly added sentence in footnote 2, referencing Table 3, is confusing to interpret. If retained, please rephrase to make it clearer that a Transmission Owner never has to increase the size of its easement/land right to satisfy this table. As drafted, our team had various interpretations and it is unclear whether the intent is that a Transmission Owner has to increase its easement or acquire land to meet this requirement, or conversely if the easement is well beyond the values in Table 3, the Transmission Owner has to maintain that the entire easement or only the values in Table 3.”Active Transmission Right of Way” is still used in the first paragraph of the Background section.In total, we suggest that the definition of Activate Transmission ROW return to the version used in the prior draft and be placed in the definition section.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
24	ITC Transmission	No	We disagree with footnote comment as this adds confusion to the standard. Is a footnote considered part of the standard or not? The reference to table #3 is something new and has never been discussed or commented on prior to this revision and appears to be a bright line concept which we are in total disagree with.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
25	FirstEnergy	No	We do not support replacement of the term Active Transmission Line Right of Way with Footnote #2. Since the term "active transmission line ROW" is used in the requirements, compliance section, and VSLs, and since the drafting team has a very definite view of what this term means, the term should be a

	Organization	Yes or No	Question 1 Comment
			definition included in the NERC Glossary. Also, since ROW is defined in the NERC Glossary, it further supports the reasons this term should also be defined. Therefore, we suggest the team revert back to the Draft 3 proposed NERC Glossary term.Lastly, we do not support the addition of Table 3. We believe this adds unnecessary prescriptiveness to the requirements. It is also not clear if this Table was intended to be mandatory because the only reference in the table is in Footnote #2. If the SDT feels this table is a useful tool that should be included in the standard, then we suggest adding it to the Guidelines section as optional information. Also, reference to this Table 3 in the Active Transmission Line ROW definition should be removed.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
26	Tampa Electric Company	No	We have concern with the "Minimum Distances" as listed in Table 3. What analytical methodology, criteria and rationale was utilized to determine each recommended distance? In addition, we have concerns regarding the change to a pre-determined distance. This seems to be a major shift from the vegetation to conductor methodology employed previously and throughout this standard? NERC/FERC must recognize that while protecting and securing grid reliability, each utility must also balance the environmental, political, customer and economic issues and impacts which will occur with the implementation of the Table 3 clearances. We question whether this is the most responsible action to take given the current state of the economy as well as the environmental and political sensitivity impacts which will result. Tampa Electric questions whether Table 3 will improve System reliability. Since the inception of standard FAC-003-1 Tampa Electric has not had a Category 1 or Category 2 outage on our 230kV Transmission System. We don't believe that the changes proposed to table 3 will improve overall service reliability. It is Tampa Electric's opinion that each utility should define the width of its own Active Transmission line ROW. However, if such a table is to be utilized, Tampa Electric recommends the following changes or adjustments to Table 3.1. Expand the table to account for the various types of Transmission construction; i.e. vertical versus horizontal conductor configurations.2. Use a distance from the outermost conductor, not the centerline. This will account for construction type and better achieve a

	Organization	Yes or No	Question 1 Comment
			consistent clearance from conductors.3. We recommend reducing the distances in Table 3 by 12.5 feet for each voltage category. 4. Specify whether the voltage is based upon the design or operating voltage.5. Reformat the voltage ranges to 100kV - 200kV, 200kV - 300kV, 300kV - 400kV, etc. as an example; this would create a more appropriate range of voltages and clearance distances. The reformatted voltage ranges eliminate confusion. For example, under the current proposal it is unclear in which category a nominal 230kV line should be since sometimes such a line can operate at up to 232kV during low-load conditions.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
27	American Transmission Company	Yes	
28	BGE Forestry Management	Yes	
29	Great River Energy	Yes	
30	MidAmerican Energy	Yes	
31	NERC Staff	Yes	
32	Pepco Holdings, Inc - Affiliates	Yes	
33	South Carolina and Gas	Yes	
34	Western Electricity Coordinating Council	Yes	

	Organization	Yes or No	Question 1 Comment
35	GDS Associates	Yes	- ROW abbreviation comes prior to the full term (marked footnote prior to the full term as stated in 5. Background). Please make correction accordingly.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
36	Duke Energy	Yes	However, due to different design attributes of transmission lines, it may be better to change the distance in Table 3 from a centerline distance to a “Minimum Full Active Transmission Line ROW Width Distance”.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
37	Idaho Power	Yes	I support the description for the active right of way. However, I believe there needs to be a provision that addresses identifying potential hazards outside the active right of ways that may pose a risk to the transmission lines.
	Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
38	Manitoba Hydro	Yes	Please add metric equivalents in the standard.While it makes some aspects easier around pointing to what we need to keep "clear" to meet NERC rules - it does limit some of our flexibility to design lines and ROWs to your own standards. Also, the minimum only applies when you have easement larger than the minimums in table 3, and I would assume that does not relieve you of the responsibility to maintain ROWs appropriately if the design of your lines requires a wider ROW.
	Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		

	Organization	Yes or No	Question 1 Comment
39	Southern California Edison Company	Yes	SCE appreciates the SDT's efforts to replace the defined term with a set of minimum distances. However, the proposed new Table 3 appears to assume a horizontal configuration of transmission lines. Thus, it would appear that those lines configured vertically (for example, two circuits on opposite sides of a tower), the "active right of way" required would be at least twice as large as that for horizontal lines. SCE respectfully recommends a footnote be added to Table 3 that allows the TO to recalculate the active right of way for lines in a vertical configuration, based on a horizontal line configuration.
	Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
40	Western Area Power Administration	Yes	Suggest using a total right-of-way width in Table 3 rather than a distance measured from centerline.
	Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
41	Tri-State Generation & Transmission	Yes	Table 3 should be referenced as a guideline only.
	Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
42	MRO's NERC Standards Review Subcommittee (nsrs)	Yes	The NSRS agrees in whole to the question but has the SDT taken into consideration the difference in ROW may be different in Urban and Rural settings?
	Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		

	Organization	Yes or No	Question 1 Comment
43	Consolidated Edison Company of New York Inc	Yes	The same verbiage in footnote number 2 should appear below Table 3 to avoid any confusion.
	Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
44	Orange and Rockland Utilities, Inc.	Yes	There should be a statement in Table 3 that is consistent with footnote number 2 stating that the minimum width of the Active Transmission Line ROW is either the full width of the easement or, if the easement is wider than the distances in Table 3, the minimum distances must not be less than the distances shown in the Table.
	Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		
45	Bonneville Power Administration	Yes	This distance is reasonable in the table, but due to widely varying designs of structures it does not give a relationship of the outside wire to edge of ROW. It should be noted as outside wire, phase or conductor to edge of ROW.In addition, the effective date should allow transmission owners time to achieve this distance, perhaps one cycle.
	Response: The NERC Standard does limit or grant property rights. Based on your comment and others, the SDT has revised the definition of Right of Way to embody the concept of an Active Transmission Right of Way. Subsequently the definition of Active Transmission Line Right of Way and Table 3 have been removed.		

2. In response to comments received regarding the terms "reasonable" and "human errors/human activity", the SDT modified the Other Section and Background Section. Do you agree? Please explain.

Summary Consideration:

Of 45 respondents, there are 3 abstentions, 38 are in agreement, and 4 are in disagreement.

The major comment issues raised are:

1. **Of the 4 in disagreement, only NERC believes "force majeure" statement is not necessary.**
2. **Three respondents believe the "force majeure" statement should be expanded to include Federal, State, Regulatory and legal interference.**

The VM SDT considerations for the major comment issues are:

1. **a) The SDT believes this language is appropriate for this standard due to the many factors related to vegetation that are truly outside the TO's control. Unlike the vast majority of other NERC standards, implementation of FAC-003 is not under the absolute control of the utilities. These influences range from landowner and agency obstacles to weather events, and as such the SDT believes the force majeure provisions should be applicable. The recognition of this provision is also supported by 90% of the industry. An attempt at similar language is contained in version 1 but it is ambiguous and lacks clarity. This language adds clarity and reduces the opportunity for mis-application. Further, TO's who elect to invoke "force majeure" must have supporting evidence of such action. The lack of a force majeure section means a Transmission Owner would have a violation of a Requirement, even if the penalty might have been mitigated by the circumstances.**

   b) However, the SDT moved the force majeure from applicability to a footnote (Footnote 2) based on comments concerning the structure of NERC standards. The footnotes are referenced in R1, R2, and R7. In R6, an exclusion clause was added in Footnote 3.

3. **The SDT recommends no expansion. The "force majeure" provision is intended to recognize circumstances that are completely outside the TO's control. Federal, State or regulatory interference is certainly a barrier but there are actions available to mitigate such interference. The TO should be aware of such interference and should take whatever corrective actions necessary, up to and including re-rating or de-energizing the line, to avoid a vegetation conflict.**

Some minor comment issues are:

1. **One respondent would like to specifically define wind speed.**
2. **Two respondents suggested moving the language elsewhere in the standard.**

The VM SDT considerations for the minor comment issues are:

1. **The SDT recommends no change. Wind speed is addressed by "fresh gale".**
2. **The SDT moved it to a footnote.**

	Organization	Yes or No	Question 2 Comment
1	MWDSC (METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA)		
2	Western Electricity Coordinating Council		
3	Central Maine Power Company, Iberdrola USA		No comment suggested.
4	NERC Staff	No	NERC staff does not support the language in the Other Section. Staff believes that the force majeure provision is unnecessary and calls into question whether NERC and the regions have enforcement discretion to take such things into account in applying other standards that do not include this type of provision.
	Response: The SDT thanks you for your comments. The SDT believes this language is appropriate for this standard due to the many factors related to vegetation that are truly outside the TO's control. Unlike the vast majority of other NERC standards, implementation of FAC-003 is not under the absolute control of the		

	Organization	Yes or No	Question 2 Comment
	utilities. These influences range from landowner and agency obstacles to weather events, and as such the SDT believes the force majeure provisions should be applicable. The recognition of this provision is also supported by 90% of the industry. An attempt at similar language is contained in version 1 but it is ambiguous and lacks clarity. This language adds clarity and reduces the opportunity for mis-application. Further, TO's who elect to invoke "force majeure" must have supporting evidence of such action.		
5	BGE Forestry Management	No	Suggest including in "4.4. Other" a phrase referencing government interference, such as "Federal, State or other regulatory interference, including legal or other legislative actions, that prevents performance to comply with this reliability standard."
	Response: The SDT thanks you for your comments. The "force majeure" provision is intended to recognize circumstances that are completely outside the TO's control. Federal, State or regulatory interferrence is certainly a barrier but there are actions available to mitigate such interference. The TO should be aware of such interference and should take whatever corrective actions necessary, up to and including re-rating or de-energizing the line, to avoid a vegetation conflict.		
6	Kansas City Power & Light	No	The theme of the "Other" section are the conditions for excluding applicable transmission facilities under certain conditions. Recommend the Drafting Team consider renaming this section to "Exclusions". In addition, the term, "Active Transmission Line Right-of-Way" is capitalized in the "Background" section. If it is determined this term should not be a definition, then this should be lower case.
	Response: The SDT thanks you for your comments. The recommendation does not materially change the "force majeure" provision and the SDT does not recommend any change. The SDT did modify the ROW definition in response to industry concerns. Capitalization is now appropriate.		
7	Xcel Energy	No	Xcel Energy urges the retention of the word "reasonable" as a modifier to "control" in Introduction, Section 4.4. The concept that a Transmission Owner should exercise reasonable control is sensible, and is of some aid in countering claims that any incident could be prevented. For example, in Colorado, the transmission of electricity has been judicially found to be subject to the highest degree of care. Without the inclusion of the word "reasonable," Xcel Energy could possibly be faced with a claim that for the exceptions set forth in Introduction, Section 4.4, to apply, the circumstances would have to be "beyond the control (using the highest degree of care) of

	Organization	Yes or No	Question 2 Comment
			Xcel Energy." Retention of "reasonable" helps counter such claims. Since this section appears to lean toward legal language, the use of the term “reasonable” is better suited for the goal of this section.
	Response: The SDT thanks you for your comments. While we understand the concerns, the word reasonable is ambigous and open to intrepretation and therefore not an appropriate modifier to the language.		
8	Allegheny Power	Yes	
9	Ameren	Yes	
10	American Transmission Company	Yes	
11	Arizona Public Service Company	Yes	
12	Bonneville Power Administration	Yes	
13	Consolidated Edison Company of New York Inc	Yes	
14	Consumers Energy Company	Yes	
15	FPL Corporate Compliance	Yes	
16	Dominion	Yes	
17	Duke Energy	Yes	

	Organization	Yes or No	Question 2 Comment
18	Entergy Services	Yes	
19	Exelon	Yes	
20	GDS Associates	Yes	
21	Hydro One	Yes	
22	Idaho Power Company	Yes	
23	ITC Transmission	Yes	
24	Manitoba Hydro	Yes	
25	MidAmerican Energy	Yes	
26	Northeast Power Coordinating Council	Yes	
27	Northeast Utilities	Yes	
28	Orange and Rockland Utilities, Inc.	Yes	
29	Pepco Holdings, Inc - Affiliates	Yes	
30	PNM	Yes	
31	PPL Electric Utilities	Yes	
32	Progress Energy	Yes	

	Organization	Yes or No	Question 2 Comment
33	South Carolina and Gas	Yes	
34	Southern Company Transmission	Yes	
35	The United Illuminating Company	Yes	
36	Tri-State Generation & Transmission	Yes	
37	Western Area Power Administration	Yes	
38	Great River Energy	Yes	GRE believes that the new definition provides greater clarity with respect what does not constitute a compliance violation versus the previous version.
	Response: The SDT thanks you for your comments and we are in agreement.		
39	CenterPoint Energy	Yes	No preference.
	Response:		
40	Southern California Edison Company	Yes	SCE generally agrees with the information contained in Part 5 - Background. However, we question the value of placing a rationale within the body of the standard. SCE respectfully recommends that the revised “Background” information be added to the beginning of the “Guidelines and Technical Basis,” which also includes explanations for various standard segments.
	Response: The SDT thanks you for your comments. It is not specific to “force majeure” and is best answered in general comments.		
41	MRO’s NERC Standards Review	Yes	The NSRS believes that the new definition provides greater clarity with respect what does not constitute a compliance violation versus the previous

	Organization	Yes or No	Question 2 Comment
	Subcommittee (nsrs)		version.
	Response: The SDT thanks you for your comments and we are in agreement.		
42	Tampa Electric Company	Yes	These changes add improved clarity and defintion to this section.
	Response: The SDT thanks you for your comments and we are in agreement.		
43	Idaho Power	Yes	This will allow the utilities to address conditions that are within their control.
	Response: The SDT thanks you for your comments and we are in agreement.		
44	FirstEnergy	Yes	While we agree with the changes proposed, we would recommend that the list contained in the "Other" section should be revised to include judicial actions such as injunctions. While this is not a natural occurring situation, it is certainly one that will prevent an entity from removing vegetation when needed or desired.
	Response: The SDT thanks you for your comments. The "force majeure" provision is intended to recognize circumstances that are completely outside the TO's control. Legal and judicial actions are certainly a barrier but there are other corrective actions available to mitigate such interference. The TO should be aware of such interference and should take whatever actions necessary, up to and including re-rating or de-energizing the line to avoid a vegetation conflict.		
45	BC Hydro	Yes	Yes but there should be more commentary around exceptions. You should get away from certain descriptive terms and be more empirical when you can to avoid ambiguity. For example "Fresh Gale" on the Beaufort Scale is not common as there are several variants to this scale and on some scales is defined as "Gale". So do you mean winds of 39-46 mph (62-74 kmh) or greater wind speed? If so, why not state that?
	Response: The SDT thanks you for your comments. The "force majeure" provision is not intended to address every possible exclusion but to be a general statement intended to recognize circumstances that are completely outside the TO's control.		

3. In response to comments received regarding the language in M1 and M2, the SDT modified the first bulleted item and added a sentence to the end of the paragraph in M1 and M2. Do you agree? Please explain.

Summary Consideration:

Of 45 respondents, there are 2 abstentions, 27 are in agreement, and 16 are in disagreement.

The major comment issues raised are:

1. **Definition of "qualified personnel".**
2. **Confusion around "real time observation of an encroachment into the MVCD" and documentation required to report a violation or attest that a violation did not occur. Also issues regarding an encroachment with no fault and/or momentary fault as being a violation.**

The VM SDT considerations for the major comment issues are:

1. **SDT changed the language to "confirmation by Transmission Owner".**
2. **Considered language proposed by Duke in comment 16 and adopted and modified by SDT.**

A minor comment issue is:

1. **The inclusion of examples in the requirement instead of the rationale box.**

The VM SDT consideration for the minor comment issue is:

1. **The SDT changed the language to "confirmation by Transmission Owner".**

	Organization	Yes or No	Question 3 Comment
1	MWDSC (METROPOLITAN		

	Organization	Yes or No	Question 3 Comment
	WATER DISTRICT OF SOUTHERN CALIFORNIA)		
2	Xcel Energy		No comments/no position
3	GDS Associates	No	- Need to specify who qualifies as "qualified personnel" to observe the vegetation condition.
	Response: Thank you for your comment. The SDT changed the wording to confirmation by the Transmission Owner.		
4	Hydro One	No	A clarification for M1 is needed regarding whether entities will have to attest to the fact that there has never been an encroachment in the MVCD.
	Response: Thank you for your comment. It is not the intent of this standard for entities to be required to prove a negative. The SDT believes the proposed language does not imply that an entity will be required to prove that an encroachment has not occurred.		
5	Northeast Power Coordinating Council	No	A clarification for M1 is needed regarding whether entities will have to attest to the fact that there has never been an encroachment in the MVCD.
	Response: Thank you for your comment. It is not the intent of this standard for entities to be required to prove a negative. The SDT believes the proposed language does not imply that an entity will be required to prove that an encroachment has not occurred.		
6	PPL Electric Utilities	No	As written M1 requires evaluation of condition by "qualified person" but no definition of qualified person given. Should be more direct and point to physical evidence of vegetation encroachment into MVCD, i.e. burned vegetation.
	Response: Thank you for your comment. The SDT changed the wording to confirmation by the Transmission Owner. It is not the intent of this standard for entities to be required to prove a negative. The SDT believes the proposed language does not imply that an entity will be required to prove that an encroachment has not occurred.		

	Organization	Yes or No	Question 3 Comment
7	CenterPoint Energy	No	CenterPoint Energy does not believe a performance based requirement should require evidence of processes and procedures to demonstrate compliance. However, if the majority of industry commenters agree with the SDT's approach, CenterPoint Energy has several concerns.Assuming R1.1 and R2.1 regarding observations of encroachments are not deleted from the Standard, then only the first paragraph regarding forms of evidence is helpful and necessary. The second paragraph is not relevant or necessary. The special qualification of Sustained Outage should be contained in R1 and R2, not M1 and M2. Also, the reference to a "Fault" in M1 and M2 instead of a "Sustained Outage" changes the scope of what is specified in R1 and R2 which is not reasonable. A "Fault" can be associated with a Momentary Outage or a Sustained Outage. The scope of R1 and R2 is specific to Sustained Outages.
	Response: Thank you for your comment. The SDT chose the word "fault" as it is a NERC defined term. A fault associated with vegetation indicates that encroachment into the MVCD occurred.		
8	Arizona Public Service Company	No	Do not agree with real-time observation. Utility can use technology to determine all rated conditions if a tree related outage occurred.
	Response: Thank you for your comment. The real-time observation reference applies to cases where vegetation encroaches into the MVCD but flash-over has not occurred. Enroachment into the MVCD where no fault occurs is the least severe violation of the requirement.		
9	MidAmerican Energy	No	Examples should be moved to the rationale boxes to avoid confusion on what is required and what is an example. All rationale boxes should have a disclaimer to the effect saying "For guidance only, not for enforcement".
	Response: Thank you for your response. Examples were included in the Requirement at the response of NERC staff to add clarity. By definition, verbiage within the rationale boxes are for guidance and are not enforcable.		
10	Kansas City Power & Light	No	In response to the informal comment period, the SDT is clear that it believes the use of encroachment as a basis for determining the effectiveness and compliance of a vegetation management program. The purpose of this Standard is to identify the criteria for effective monitoring of vegetation in

	Organization	Yes or No	Question 3 Comment
			transmission right-of-way and to take appropriate actions when that monitoring identifies the need to “clear” vegetation to prevent potential transmission facility outages resulting from contact with vegetation. These proposed Measures as written do not give credit to the Transmission Owners for effectively monitoring their systems and taking appropriate actions in regard to vegetation clearing. Why does it make sense to punish and penalize a Transmission Owner for discovering an encroachment when they take the appropriate actions to remedy the condition before any facility outage occurs that results in compromising the reliability of the Bulk Electric System? These Measures and Standard should recognize the good practices of effective response to a vegetation condition and penalize ineffective response. Highly recommend the SDT consider including appropriate language to recognize effective remedial actions by Transmission Owners and by doing so, recognize effective efforts instead of punishing them.In addition, proving encroachments have not occurred will pose audit challenges in determining that encroachments have not occurred for the Auditors as well as Registered Entities. If no encroachments occur, then there is nothing to report or record. This is a weak platform to stand compliance on. Facility interruption events caused by vegetation contacts is definitively measurable and recordable. Recommend the SDT reconsider the concept of compliance with FAC-003 on the basis of sustained outages.
	Response: Thank you for your comment. The real-time observation reference applies to cases where vegetation encroaches into the MVCD but flash-over has not occurred. Enroachment into the MVCD where no fault occurs is the least severe violation of the requirement. It is not the intent of this standard for entities to be required to prove a negative. The SDT believes the proposed language does not imply that an entity will be required to prove that an encroachment has not occurred.		
11	BGE Forestry Management	No	M1 & M2 bullet: “Real-time observation of any MVCD encroachments.” implies that real-time observation of vegetation encroachment ensures reliable operation the Bulk Electric System. The reliability standard objective states;”To improve the reliability of the electric Transmission system by preventing those vegetation related outages that could lead to Cascading.”However, real time observation of current operating conditions provides no assurance that vegetation will not lead to outages. BGE recommends removing the language. If an inspector finds vegetation encroaching into the MVCD during a visual inspection he / she should

	Organization	Yes or No	Question 3 Comment
			immediately initiate an Immediate Threat Notification. Therefore, this measure has no value.
	Response: Thank you for your comment. The real-time observation reference applies to cases where vegetation encroaches into the MVCD but flash-over has not occurred. Enroachment into the MVCD where no fault occurs is the least severe violation of the requirement.		
12	PNM	No	Needs a definition of Real Time Observations
	Response: Thank you for your comment. The SDT believes that “Real Time” observations (the actual time during which the observation occurs) is sufficiently clear.		
13	Consumers Energy Company	No	None of the three examples of acceptable forms of evidence provided in the revision prove that a Transmission Owner actively managed vegetation to prevent encroachment into the MVCD. The Measure should require proof of active ROW clearing activity per the transmission vegetation management plan, such as invoicing or crew field reports or vegetation inspection data from the annual vegetation inspection.
	Response: Thank you for your comment. The SDT would suggest you refer to R6 and R7, which addresses evidence of an annual vegetation inspection and work plan.		
14	BC Hydro	No	Overall, the definition of these measures is improved over draft 3. However, the standard should better define who a “qualified person” is and who has the authority to make attestations. R1 and R2 could be better defined relative to the standard definitions in section 4.2 as to what voltage levels in R2 are part of the standard and what is excluded. That is:R1 is any circuit that is an element of an IROL or WECC transfer path regardless of the transmission voltage.R2 is any circuit >200kV which is not an element of an IROL or WECC transfer path.Lower voltage circuits that do not fit the R1 definition are not part of this standard.
	Response: Thank you for your comment. The SDT changed the wording to confirmation by the Transmission Owner. R1 and R2 intentionally differentiate between the components of the transmission system that are part of the IROL or WECC Transfer Path and the BES. The SDT believes that violations in the IROL or WECC Transfer Paths pose a greater risk of cascading events, and therefore carry higher VSLs.		

	Organization	Yes or No	Question 3 Comment
15	Central Maine Power Company, Iberdrola USA	No	Recommend SDT create two measures one measure if a tree violated the MVCD and no outage occurred and second measure and severity level if an outage occurred
	Response: The SDT believes that enroachments into the MVCD where no fault occurs are a violation to the standard and should be included in R1 and R2.		
16	Duke Energy	No	The last sentence of this modification could be misinterpreted by a compliance representative to imply that all Faults must be investigated to eliminate or confirm vegetation as the cause of the fault. There are several sources (e.g. lightning, wind-blown debris) of Faults and several appropriate operational responses, some of which may not include field investigations, depending on the circumstances surrounding each Fault. Thus, the current wording is gray and should be modified to aid industry's understanding and thus to ensure compliance.The interpretation we suggest may not be obvious, but our experience with previous interpretations of certain facets of FAC-003-01 would indicate the need to better define the expectation.A potential modification to the last sentence of M1/M2 could be:If a later confirmation of a Fault by a qualified person shows that a vegetation encroachment within the MVCD has occurred, this shall be considered the equivalent of a Real-time observation.
	Response: Thank you for your comment. The SDT agrees with your recommendation and has adopted the proposed language. The SDT believes that faults that occur on applicable lines included in R1 and R2 should be investigated to determine if the cause was vegetation related. If an entity can determine to their satisfaction, through documentable means such as through technology or other sources, that the fault was caused by some other reason (i.e. lightning), it is the entity's decision whether or not to investigate further.		
17	FPL Corporate Compliance	No	The measure is adding to the requirement. The measure should define how a requirement is met and not interpret or add to the requirement, otherwise this will add to confusion, instead of clarity, which should be the goal of any revised reliability Standard.Also, the measure implies that a fault investigation must be done. As written, momentary outages are included, and a fault investigation should not be required for momentary outage.It also places the same weight of violation on a momentary outage as it does a Sustained outage, which appears on its face not to appropriate nor

	Organization	Yes or No	Question 3 Comment
			necessary to meet the goal of FAC-003-2. In addition, an outage investigation is not a finite process that produces identical homogenous results every time. Of particular concern is the possibility that should a Transmission Owner have one or more momentary outages and not find the cause, then later have another outage (Sustained or Momentary), such a finding appears to lead to a multiple violation. This is inconsistent with focusing requirements on reliability risks to the bulk electric system.
	Response: Thank you for your comment. A fault caused by the grow-in, fall-in, or blow-in of vegetation on the active right-of-way is a violation of the requirements regardless of whether the fault was momentary or sustained. Based on other comments, the SDT has modified the language in M1/M2.		
18	NERC Staff	No	With respect to both M1 and M2, NERC staff finds the “acceptable forms of evidence” incomplete. To assess compliance, the auditors would also need to see the processes and procedures identified under Requirement R3 and the annual work plan under Requirement R7 to see how the entity planned to prevent sustained outages and what the entity had done to implement that plan. Finally, what is the purpose of the following sentence?: “If an investigation of a Fault by a qualified person confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered a Real-time observation.” Recommend adding each report of a real-time observation of encroachment into the MVCD to the periodic data submittal.
	Response: Thank you for your comment. The SDT believes that an attempt to list all “acceptable forms of evidence” would be difficult, as entities employ a myriad of documentation types. The SDT agrees that an auditor would need to see the processes and procedures indentified under R3 and R7 to perform an audit. An auditor with an understanding of vegetation management would be able to validate “acceptable forms of evidence” as part of compliance audit process. Real time observations of an encroachment into the MVCD is a violation of the standard and should be documented and self-reported. The RE’s currently require periodic reporting.		
19	Allegheny Power	Yes	
20	Ameren	Yes	
21	American	Yes	

	Organization	Yes or No	Question 3 Comment
	Transmission Company		
22	Bonneville Power Administration	Yes	
23	Consolidated Edison Company of New York Inc	Yes	
24	Dominion	Yes	
25	Exelon	Yes	
26	Idaho Power	Yes	
27	Idaho Power Company	Yes	
28	ITC Transmission	Yes	
29	Manitoba Hydro	Yes	
30	MRO’s NERC Standards Review Subcommittee (nsrs)	Yes	
31	Northeast Utilities	Yes	
32	Orange and Rockland Utilities, Inc.	Yes	
33	Pepco Holdings, Inc – Affiliates	Yes	

	Organization	Yes or No	Question 3 Comment
34	Progress Energy	Yes	
35	South Carolina and Gas	Yes	
36	Southern Company Transmission	Yes	
37	The United Illuminating Company	Yes	
38	Tri-State Generation & Transmission	Yes	
39	FirstEnergy	Yes	Although we agree with the language of M1 and M2 for the proposed R1 and R2 in the standard being balloted, we support the alternate versions of R1 and R2 (see comments in Question 6) and wish to see M1 and M2 developed for the alternate R1 and R2.
	Response: Thank you for your comment.		
40	Great River Energy	Yes	GRE agrees with the revisions made to this standard since the last posting and requests clarification on what constitutes a qualified person.
	Response: Thank you for your comment. The SDT changed the wording to confirmation by the Transmission Owner.		
41	Western Electricity Coordinating Council	Yes	however the statement of acceptable forms of evidence implies that a dated attestation alone could provide evidence of compliance. An attestation alone would not represent sufficient evidence to support a conclusion of compliance with encroachment limits only of the absence of an outage.
	Response: Thank you for your comment. Real time observations of an encroachment into the MVCD is a violation of the standard and should be documented and self-reported.		

	Organization	Yes or No	Question 3 Comment
42	Western Area Power Administration	Yes	However, the last sentence added to the measure is imprecise and introduces undesirable subjectivity and confusion to the process for determining a compliance violation.
	Response: Thank you for your comment. Based on the recommendation from several commentors, the last sentence in M1/M2 has been modified.		
43	Southern California Edison Company	Yes	SCE generally agrees with the revisions to M1 and M2, however we would suggest the last sentence of the second paragraphs in both M1 and M2 be modified to read: M1- Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. If an investigation of a Fault, by a qualified person, confirms that a vegetation encroachment, as described in R1 items 2-4 (above), occurred within the MVCD occurred, then it shall be considered a Real-time observation.M2- Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. If an investigation of a Fault, by a qualified person, confirms that a vegetation encroachment, as described in R2 items 2-4 (above), occurred within the MVCD occurred, then it shall be considered a Real-time observation.
	Response: Thank you for your comment. Based on the recommendation from several commentors, the last sentence in M1/M2 has been modified.		
44	Tampa Electric Company	Yes	These changes allow for qualified review of field findings.
	Response: Thank you for your comment.		
45	Entergy Services	Yes	We agree, IF the determination is made by a Qualified Person to have been caused by vegetation breaking the MVCD (if not breaking MVCD in real time when observed) based on close observation/inspection and hard evidence that a Flashover occurred, and that there is no evidence that the issues spotted on the tree were caused by environmental or biological symptoms or stressors of the tree in question. Hard evidence has to be present to classify

	Organization	Yes or No	Question 3 Comment
			the item as a vegetation outage if the tree is not within MVCD when the real time observation is made.....an assumption cannot be made that vegetation was the cause of an outage if the tree is situated at a distance that is greater than MVCD when observed unless there is hard evidence supporting the flashover as determined by a qualified person.
	Response: Thank you for your comment.		

4. In response to comments received that requirement R3 is deficient in detail, the SDT modified the requirement. Do you agree? Please explain.

Summary Consideration:

Of 45 respondents, there are 32 in agreement, 12 in disagreement and1 abstention.

The major comment issues raised are:

1. **The additional wording placed in the requirement after the first sentence adds confusion to the extent of documentation that will be required.**
2. **The use of the phrase "incorporate the dynamics" adds confusion to the requirement.**

The VM SDT considerations for the major comment issues are:

1. **The response pointed out that the reason that the additional wording was inserted was due to the numerous comments from the previous posting that the requirement needed more specificity.**
2. **The SDT agreed with some suggested wording to replace the phrase "incorporate the dynamics" and revised the requirement accordingly.**

Some minor comment issues are:

1. **One commenter questioned the use of the word "intent" in the rationale.**
2. **One commenter questioned the language of the measure.**
3. **One commenter was concerned that the removal of the programmatic details renders the requirement less auditable and questionably effective.**

The VM SDT considerations for the minor comment issues are:

1. **The wording in the rationale was changed to eliminate the word "intent".**
2. **In the response to the commenter questioning the language of the measure, the SDT explained that the focus of the measure is on the logic test of the Transmission Owner's vegetation maintenance program.**

3. In response to the commenter concerned about the programmatic details being removed, the SDT responded by explaining various ways that this requirement could be audited and further explained the main focus of the requirement.

	Organization	Yes or No	Question 4 Comment
1	MWDSC (METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA)		
2	GDS Associates	No	- We suggest to eliminate / change the word “dynamics” because can create confusion with regards to the extent of documentation that has to be prepared.- Requirement should clearly state the criteria as in the maximum design (rating) or maximum operat
	Response: The SDT thanks you for your comment. The intent of the more detailed wording of R3 in this version of the Standard is to make sure that the Transmission Owner adequately documents and demonstrates that it understands the complex relationship of conductor movement under thermal and wind load and vegetation growing and moving in proximity to the line. In light of your comment, and similar comments from others, the SDT has revised the wording of R3. We feel that this change will alleviate any perceived confusion.		
3	PPL Electric Utilities	No	As written, R3 now requires documentation of conductor dynamics as related to ratings and rated operational conditions. Not clear how this information is to be presented and documented and how vegetation conditions that exist are to be documented to provide evidence that management processes and procedures are adequate to prevent encroachment into MCVD.
	Response: The SDT thanks you for your comment. The Technical Reference Document attempts to provide further explanation, along with examples, of how to present this information. While this information is not in the Standard itself, the supplemental information in the Technical Reference Document should help the Transmission Owner understand the SDT’s intent for the requirement. Also, The SDT has revised the wording in R3 and has removed the word “dynamics”.		

	Organization	Yes or No	Question 4 Comment
4	Great River Energy	No	GRE does not believe that the new specificity that has been added to R3 will improve the reliability of the BES. It is our opinion that the requirement would have been clearer if it had ended after the first sentence. The additional language after the first sentence does not improve clarity.In measures for other requirements the SDT has done a very good job of stating and clarifying (in their opinion) what acceptable forms of evidence are. M3 would benefit from this type of clarification.
	Response: The SDT thanks you for your comment. The previous version of the Standard was crafted very much as you suggest. Many commenters disagreed with this approach, which led to the SDT crafting this more verbose version.		
5	Kansas City Power & Light	No	It is unclear that this requirement may utilize the industry practice of “ruling span” methods to determine the vegetation clearances for a transmission facility. “Ruling span” methods are used to determine the construction design for transmission facilities and includes maintaining safe clearance distances. This requirement could be interpreted as being applied to every individual span to determine vegetation clearances for a transmission facility which would not be practical.
	Response: The SDT thanks you for your comment. The intent of R3 in this version of the Standard is to make sure that the Transmission Owner adequately documents and demonstrates that it understands the complex relationship of conductor movement under thermal and wind load and vegetation growing and moving in proximity to the line. It leaves the decision to the Transmission Owner how to satisfy this “competency based” requirement. While a Transmission Owner could certainly take the approach that each individual span be addressed separately, it is also possible for a Transmission Owner to have a specific “vegetation maximum height” approach, based on the minimum ground clearance specification of an entire line. Either approach would satisfy this requirement.		
6	MidAmerican Energy	No	MidAmerican supports the additional detail the R3 should end after the first sentence. The additional detail should be moved to the rationale box as additional guidance.
	Response: The SDT thanks you for your comment. If we understand your comment, the reason that R3 has greater detail was due to comments received after the last posting. The SDT felt compeled to add this additional information.		

	Organization	Yes or No	Question 4 Comment
7	Xcel Energy	No	R3 requires the Transmission Owner to have a documented process that shall contain certain items. Please bulletize these items for clarity.Additionally, the measure for this requirement indicates that the process document elements 'prevent' encroachment. It is presumed that the elements identified in the requirement are what need to be addressed in order to minimize the likelihood of encroachment. Essentially, M3 should be reworded to state "The procedures, processes, or specifications provided incorporate the elements identified in R3 (dynamics of a transmission line conductor's...)
	Response: : The SDT thanks you for your comment. The SDT feels that the requirement is adequate in a non-bullet form. R3 has been revised to clarify the intent of this "competency based" requirement. The measure for this requirement should be a "logic" test looking at the methodology that the Transmission Owner uses in order to determine what vegetation actions need to take place. The Technical Reference Document gives examples of several ways to satisfy this requirement. The SDT feels that the measure as stated is adequate.		
8	Southern California Edison Company	No	SCE prefers the Draft 3 version of R3 which read:"Each Transmission Owner shall have a documented transmission vegetation management program that describes how it conducts work on its Active Transmission Line ROWs to avoid Sustained Outages due to vegetation, considering all possible locations the conductor may occupy assuming operation within Rating and Rated Electrical Operating Conditions."However, if the SDT believes it is prudent to revise R3 in response to certain commenters, SCE would respectfully recommend R3 be revised to read:"Each Transmission Owner shall document the procedures, processes, or specifications it uses to prevent the encroachment of vegetation into the MVCD. Such documentation will account for the movement of transmission line conductors under their Rating and Rated Electrical Operating Conditions; and the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the Transmission Owner's applicable lines."
	Response: The SDT thanks you for your comment. The SDT agrees that the wording in R3 should be modified. R3 has been revised to remove the reference to "incorporate the dynamics" and has recrafted the requirement wording similar to your latter recommendation.		

	Organization	Yes or No	Question 4 Comment
9	CenterPoint Energy	No	See response to Q3 above. However, assuming R3 is not revised to exclude processes and procedures, we have no preference to the wording between the two drafts.
	Response: The SDT thanks you for your comment.		
10	Arizona Public Service Company	No	Still lacks detailed information. SDT needs to specify the documentation it is left up to interpretation by the utility.
	Response: The SDT thanks you for your comment. The SDT feels that the combination of the requirement wording and the examples and explanations in the Technical Reference Document are sufficient detail to portray the intent.		
11	MRO's NERC Standards Review Subcommittee (nsrs)	No	The NSRS does not believe that the new specificity that has been added to R3 will improve the reliability of the BES. It is our opinion that the requirement would have been clearer if it had ended after the first sentence. The additional language after the first sentence does not improve clarity. The whole (as written) requirement may be interpreted as a requirement for "each span" of Transmission line to which the Requirement will be applied. In measures for other requirements the SDT has done a very good job of stating and clarifying (in their opinion) what acceptable forms of evidence are. M3 would benefit from this type of clarification.
	Response: The SDT thanks you for your comment. The previous version of the Standard was crafted very much as you suggest. Many commenters disagreed with this approach, which led to the SDT to address this issue by adding the specificity. **R3 is a "competency based" requirement. The measure should be whether the methodology used by the TO to maintain vegetation passes the basic logic test. (eg: Our max growth rate is 3' per year. We have a minimum ground clearance spec for 230 kV of 24 feet at maximum sag. We maintain the lines every three years. During maintenance of 230 kV lines we remove all vegetation over 11.5 feet high) For a "results based" standard, the emphasis should be on the Tranmssion Owner demonstrating competency in its approach, however simple or complex that approach may be**		
12	NERC Staff	No	The removal of programmatic details from R3 renders the auditing task much more difficult. How does one assess the quality of the program except

	Organization	Yes or No	Question 4 Comment
			through the results required in R1 and R2? Since maintaining specific cut-to clearances is not required, there is much greater subjectivity in application that greatly complicates the auditor job. If the team does not want to limit the available approaches, it could provide flexibility by offering an array of deterministic formulas or approaches for maintaining vegetation. This might include maintaining vegetation to remain within a certain height from the ground given maximum sag distances. Additionally, this requirement does not seem to require the entity to actually follow its policies and procedures (unlike, for instance, R7). What is a violation here? Not having the documented procedure(s) OR whether the documented procedure(s) actually demonstrate that the entity can prevent encroachment? NERC staff is also concerned with some of the language in M3. Consider the following modification: “The Transmission Owner will have procedures, processes, or specifications as identified in Requirement R3, records showing work done to support its annual work plan identified in Requirement R7, and its quarterly vegetation reports, to demonstrate that it can prevent encroachment into the MVCD.” Finally, with respect to the Rationale associated with R3, how would NERC enforce poor intent or a poor indication of competency (especially if the entity was performing well)? Recommend: Provide a basis for evaluating whether the Transmission Owner’s procedures, processes, or specifications used to maintaining vegetation are achieving that goal. There may be many acceptable approaches to controlling vegetation so that it does not encroach into the MVCD. And one small copyedit: “interrelationships” should not have a hyphen.
	Response: The SDT thanks you for your comment.		

	Organization	Yes or No	Question 4 Comment
	Regarding the comments pertaining to the requirement wording: The intent of R3 in this version of the Standard is to make sure that the Transmission Owner adequately documents and demonstrates an understanding of the complex relationship of conductor movement under thermal and wind load and vegetation growing and moving in proximity to the line. The SDT points out that inclusion of a programatic list of activities by itself does nothing to to ensure reliability. R3 is a competency based requirement. The audit test is simply one of logic. Does the methodology the TO conveys in R3 logically ensure that no encroachments into the MVCD occur? The SDT feels that it is important for the Transmission Owner to have the flexiblity to choose how it satisfies this requirement and not to provide a limited menu of approaches that could be used. (eg: Our max growth rate is 3' per year. We have a minimum ground clearance spec for 230 kV of 24 feet at maximum sag. We maintain the lines every three years. During maintenance of 230 kV lines we remove all vegetation over 11.5 feet high) For a "results based" standard, the emphasis should be on the Tranmssion Owner demonstrating competency in its approach, however simple or complex that approach may be. The violation for this requirement would be either the TO failed to specify its approach or that the approach specified does not pass the logic test. Regarding the comments pertaining to the measures M3: The SDT feels that an auditor knowledgeable of utility vegetation management work would be capable to evaluate if a well documented approach is sufficient to ensure no vegetation encroachments into the MVCD. Regarding the comments pertaining to the Rationale: The drafting team agrees that "intent" is not measurable or enforceable and has removed it from the rationale. The evaluation and measurement of the competency is listed above.		
13	Consumers Energy Company	No	This really is another attempt at avoiding defining a minimum clearance specification and is not practical. As written, this would require each Transmission Owner to define and document the procedures, processes or specification by individual span for every line owned or operated by the Transmission Owner. Each span varies in length and profile and a single line may have several different conductor types with different load ratings. Line loadings will vary along the line based on substation taps, etc. The dynamics described in the language could only be done on an individual span basis to be reasonably accurate. This is not practical from a planning standpoint or from a standpoint of implementing clearing work in the field.
	Response: The SDT thanks you for your comment. The intent of R3 in this version of the Standard is to make sure that the Transmission Owner adequately documents and demonstrates that it understands the complex relationship of conductor movement under thermal and wind load and vegetation growing and moving in proximity to the line. It leaves the decision to the Transmission Owner how to satisfy this		

	Organization	Yes or No	Question 4 Comment
	"competency based" requirement. While a Transmission Owner could certainly take the approach that each individual span be addressed separately, it is also possible for a Transmission Owner to have a specific "vegetation maximum height" approach based on the minimum ground clearance specification of an entire line. Either extreme would satisfy this requirement. A Transmission Owner also could have an approach that contained a mixture of the two extremes.		
14	Allegheny Power	Yes	
15	Ameren	Yes	
16	American Transmission Company	Yes	
17	BGE Forestry Management	Yes	
18	Bonneville Power Administration	Yes	
19	Central Maine Power Company, Iberdrola USA	Yes	
20	Consolidated Edison Company of New York Inc	Yes	
21	FPL Corporate Compliance	Yes	
22	Duke Energy	Yes	
23	Entergy Services	Yes	

	Organization	Yes or No	Question 4 Comment
24	Exelon	Yes	
25	FirstEnergy	Yes	
26	Hydro One	Yes	
27	Idaho Power	Yes	
28	Idaho Power Company	Yes	
29	ITC Transmission	Yes	
30	Manitoba Hydro	Yes	
31	Northeast Power Coordinating Council	Yes	
32	Northeast Utilities	Yes	
33	Orange and Rockland Utilities, Inc.	Yes	
34	Pepco Holdings, Inc - Affiliates	Yes	
35	PNM	Yes	
36	Progress Energy	Yes	
37	South Carolina and Gas	Yes	
38	The United	Yes	

	Organization	Yes or No	Question 4 Comment
	Illuminating Company		
39	Tri-State Generation & Transmission	Yes	
40	Western Area Power Administration	Yes	
41	Western Electricity Coordinating Council	Yes	
	Response:		
42	Dominion	Yes	Although we agree with the intent of the proposed language, we feel the requirement should be revised to read:Each Transmission Owner shall document the procedures, processes, or specifications it uses to prevent the encroachment of vegetation into the MVCD. Such procedures, processes, or specifications shall consider the dynamics of a transmission line conductor's movement throughout its Rating and Rated Electrical Operating Conditions and the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the Transmission Owner's applicable lines.
	Response: The SDT thanks you for your comment. The SDT agrees that the wording in R3 should be modified. R3 has been revised to remove the reference to "incorporate the dynamics" and has recrafted the requirement wording similar to your latter recommendation.		
43	BC Hydro	Yes	As a competency requirement, R3 seems to be missing any requirement for a utility to define who is qualified to develop these plans, which is a departure from FAC-003-1 R1.3. I think that the utility should in their standards define who is qualified to develop their transmission vegetation management program
	Response: The SDT thanks you for your comment. While the SDT agrees that personnel qualifications are important in any pursuit for perfection, the overall approach for this version of the Standard is a "results based' product. In light of that, the SDT does not feel that a "fill in the blank" requirement for personnel		

	Organization	Yes or No	Question 4 Comment
	qualifications is necessary.		
44	Tampa Electric Company	Yes	This better clarifies section R3
	Response:		
45	Southern Company Transmission	Yes	While voting yes we are concerned about the interpretation of the expanded verbiage, how much documentation will be enough.
	Response: The SDT thanks you for your comment. The Technical Reference Document attempts to provide further explanation, along with examples, of how to present this information. While these examples are not in the Standard itself, the supplemental information in the Technical Reference Document should help the Transmission Owner understand the SDT's intent for the requirement, and therefore the documentation required to demonstrate competency.		

5. In response to comments received that requirement R7 is unclear with respect to flexible work plans, the SDT modified the requirement. Do you agree? Please explain.

Summary Consideration:

Of 45 respondents, there are 2 abstentions, 34 are in agreement, and 9 are in disagreement.

The major comment issues raised by those in disagreement are:

1. **The Requirement is vague and needs more specificity and explanation.**
    - **Does not require development of the Annual Vegetation Work Plan**
    - **Language allowing modifications to the Work Plan should specifically require documentation of changes**
    - **M7 is measuring completion of Work Plan, not prevention of encroachments into the MVCD**
    - **The phrase "…provided they do not put the transmission system at risk of a vegetation encroachment" could be better written as "…they do not allow encroachment of vegetation into the MVCD"**
2. **Examples describing potential reasons for plan modification should be clarified or eliminated.**
    - **Decreases in funding not valid.**
    - **Encroachments due to Major Storms are exempted in Footnote 2. R7 allows modification to Plan due to major storms but does not allow encroachments associated with plan change.**
    - **Generally. the examples identified are broad in nature**

Some minor comment issues are:

1. **Eliminate requirement or use the first sentence only.**
2. **Some concern with lack of agreement of language with other parts of the Standard.**

The VM SDT appreciated both the major and minor comment issues identified but decided that the requirement and measures are appropriate and clear as currently written and did not modify any of the language. The SDT reviewed the Funding Adjustment example for R7 and feels this is a valid reason for modifying the Annual Plan keeping in mind that a modification must not place the transmission system at risk of vegetation encroachment into the MVCD. In addition, as expressed in the Rationale, R7 sets the expectation that the work identified in the

annual work plan will be completed as planned. Documentation of the work completed (and any necessary modifications) as written together with the lack of a violation to either Requirement 1 or Requirement 2 is the overall reliability goal. The metric for the work plan is the percentage of the plan completed. The lack of a violation of R1 or R2 is the outcome of the ideal work plan. It is the responsibility of the Transmission Owner to manage the quality of the work plan and its associated modifications to mitigate the risk of a violation of R1 or R2. With Version 2, an outage is now clearly a violation of R1 and R2 and should not be linked to a failure of the work plan. The measure for the work plan is the percentage of the completed work as planned and we do not need to be subjectively trying to evaluate the quality of the Transmission Owner's work plan with this measure.

	Organization	Yes or No	Question 5 Comment
1	GDS Associates		
2	MWDSC (METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA)		
3	Western Area Power Administration	No	As the list of “examples of reasons for modification” is not all inclusive, it is unnecessary and could result in confusion regarding compliance when a scenario other than one listed requires a change. Further, documentation of changes to the annual plan adds unnecessary administrative burden which is inconsistent with a performance based standards approach.
	Response: Thank you for your response. The SDT feels the list of examples, while not all inclusive, is helpful to the TO in determining how and when to apply flexibility to its annual plan, when required. It is important the TO documents modefication to the plan to insure the work not completed during that period is carried over and completed within a reasonable time frame.		
4	Ameren	No	Funding Adjustments (increase or decrease) - need more description to imply only when planned vegetation work is “over and above”.

	Organization	Yes or No	Question 5 Comment
	Response: Thank you for your comment. The SDT reviewed the Funding Adjustment example for R7 and feels this is a valid reason for modefying the Annual Plan keeping in mind that a modefication must not place the transmission system at risk of vegetation encroachement into the MVCD.		
5	MidAmerican Energy	No	MidAmerican supports the additional detail. However R7 should end after the first sentence. All additional material should be moved to the rationale box.
	Response: Thank you for your comment. The position of the SDT is to have this langiage in the requirement such to allow for flexibility to the work plan. Keep in mind Rationale language is clarifying documentation and not enforcable. The SDT feels it is important that the TO have the flexibility to revise its Annual Plan which is subject to many issues that can influence the completion of work.		
6	The United Illuminating Company	No	R1 and R2 are requirements that no encroachment occurs. R7, as proposed, requires a VMP to be completed to ensure no encroachment occurs. The Supplemental Reference for R7 does not describe the requirement of the annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. The Reference states the requirement is established to diminish the risk of encroachment; which is very different from ensuring no encroachment. In the Reference for R7 the word “ensure” is only used to describe that flexibility in the VMP is allowed to ensure the reliability of the Transmission System.M7 is measuring work plan completion not the prevention of encroachment. United Illuminating suggests that R7 be changed to: Each Transmission Owner shall complete the work in an annual vegetation work plan to manage the prevention of vegetation encroachments occur within the MVCD. In this way, a violation of R1/R2 does not necessarily mean R7 is violated. The entity does not avoid a penalty for an encroachment because a violation of R1/R2 occurs for actual encroachment. If an encroachment occurs the compliance enforcement authority can review the entities vegetation management plan to determine if it is compliance with R7/M7.
	Response: Thank you for your comments. As expressed in the Rationale, R7 sets the expectation that the work identified in the annual work plan will be completed as planned. Documentation of the work completed (and any necessary modifications) as written together with the lack of a violation to either Requirement 1 or Requirement 2 is the overall reliability goal. The metric for the work plan is the percentage of the plan completed. The lack of a violation of R1 or R2 is the outcome of the ideal work plan. It is the responsibility of		

	Organization	Yes or No	Question 5 Comment
	the Transmission Owner to manage the quality of the work plan and its associated modifications to mitigate the risk of a violation of R1 or R2. With Version 2, an outage is now clearly a violation of R1 and R2 and should not be linked to a failure of the work plan. The measure for the work plan is the percentage of the completed work as planned and we do not need to be subjectively trying to evaluate the quality of the Transmission Owner's work plan with this measure.		
7	CenterPoint Energy	No	See response to Q3 above.However, assuming R7 is not revised to exclude processes and procedures, the new wording is preferred since it is more specific. Additionally, a new ambiguous phrase is introduced, "provided they do not put the transmission system at risk of a vegetation encroachment", which we recommend to be changed to more specific wording, "provided they do not allow encroachment of vegetation into the MVCD".
	Response: Thank you for your comments. The SDT felt the language was appropriate.		
8	Southern Company Transmission	No	The first sentence of the Requirement 7 Rationale conflicts with the second sentence. The R7 Rationale should be reworded as follows:"This requirement sets the expectation that the work identified in the annual work plan should be completed as planned. However, an annual vegetation work plan must allow for work to be modified in response to changing conditions. These modifications must take into consideration the anticipated growth of vegetation and all other environmental factors, provided that the changes do not cause a vegetation encroachment within the MVCD."
	Response: Thank you for your comments. The SDT felt the language was appropriate.		
9	NERC Staff	No	This is the first instance in which an annual work plan is discussed. It would appear necessary to first develop an annual work plan component of the overall vegetation management program. There should also be some performance review or expectation that the annual plan as implemented achieved the intended program objectives, or that modifications would be necessary. Does R7 require both that a Transmission Owner has an annual vegetation

	Organization	Yes or No	Question 5 Comment
			work plan AND that it completes the work plan? Detail is required as to what is expected in the work plan, as there is currently no basis to judge whether the work plan is adequate or not adequate. And what does a modification entail? Does this mean reduction of performance, delay in performance, or complete postponement of performance? NERC staff is also concerned with the list of examples one might use to modify an annual plan. Several of these items should not pose any greater risk to vegetation contact and render the requirement virtually unenforceable. It provides a wide array of reasons to postpone vegetation management and may make it a very low priority for an entity: • “Rescheduling work between growing seasons”: This could be an honest change (if there are unexpected seasonal changes) or it could reflect bad initial planning. If there will be occasion for auditors and investigators to distinguish, there should be guidance on differentiating. • “Crew or contractor availability”: This could be an honest change (if there is an unexpected labor dispute or if crews are needed to help a neighboring utility during an unexpected emergency) or it could reflect bad initial planning. If there will be occasion for auditors and investigators to distinguish, there should be guidance on differentiating. Alternatively, it could be removed from the list as it is within the exclusive control of the Transmission Owner. • “Identified unanticipated high priority work”: This could be an honest change or it could reflect bad initial planning. If there will be occasion for auditors and investigators to distinguish, there should be guidance on differentiating. It is also vague and would necessitate a judgment call for enforcement. • “Permitting delays”: Annual plans should account for anticipated permitting schedules and maybe even add a factor for uncertainty. It is a planning issue for the entity and should not be an acceptable excuse for not conducting vegetation management. • “Land ownership changed”: If a landowner has the ability to affect the reliability of the bulk power system, the landowner should be subject to

	Organization	Yes or No	Question 5 Comment
			the reliability standards. A registered entity should be responsible for the land in its ROW, especially if it has turned control of the land, and the ability to affect reliability of the BPS, over to another entity or person for financial gain. • “Funding adjustments”: NERC staff is not convinced that this is a legitimate reason for adjusting an annual vegetation work plan. Economic considerations should not be a reason to delay or modify vegetation management. • “Emerging technologies”: It is unclear what this example is intended to accomplish. In general, these examples should be bounded in some way to ensure that a modification due to one of their occurrences does not impart a greater risk of vegetation contact.
	Response: Thank you for your comments. Per the SDT, developing the annual work plan is an understood requirement in order for the TO to complete the work plan. Thus, a requirement to develop the plan is not needed. R3 specifies the processes, procedures and/or specifications that are utilized by a TO to prevent an encroachment of the MVCD. This “Competency Based” requirement sets the core foundation that a TO will utilize to develop their annual work plan. **As expressed in the Rationale, R7 sets the expectation that the work identified in the annual work plan will be completed as planned. Documentation of the work completed (and any necessary modifications) as written together with the lack of a violation to either Requirement 1 or Requirement 2 is the overall reliability goal. The metric for the work plan is the percentage of the plan completed. The lack of a violation of R1 or R2 is the outcome of the ideal work plan. It is the responsibility of the Transmission Owner to manage the quality of the work plan and its associated modifications to mitigate the risk of a violation of R1 or R2. With Version 2, an outage is now clearly a violation of R1 and R2 and should not be linked to a failure of the work plan. The measure for the work plan is the percentage of the completed work as planned and we do not need to be subjectively trying to evaluate the quality of the Transmission Owner’s work plan with this measure.** **By bounding the flexibility as advocated, there are several variables involved such it makes it impractical to be able to address the many operational scenerios that a TO may experience. Thus, without being very prescriptive, the SDT feels that it is best to provide general guidance to what are valid modifications to the work plan.**		

	Organization	Yes or No	Question 5 Comment
10	Kansas City Power & Light	No	This requirement is in direct conflict with the “exclusions” as described in section 4.4. Section 4.4 makes it clear that effects of “major storms” on a vegetation programs efforts will be allowed as an exclusion toward compliance with these requirements, yet, R7 does not allow any encroachment due to modifications to a vegetation plans efforts due the “Major Storms” (second bullet) or “Weather conditions/Accessibility” (bullet 6). Please explain what is intended here that is different than what was intended in section 4.4.In addition, this presents some audit difficulties regarding the notion of detecting a “modified work plan”. Once a work plan is altered and new objectives are laid out, that becomes the plan and the plans that were replaced may be discarded since they would be of no value. Further, what difference does it make to track or monitor any changes to a work plan provided effective vegetation management is maintained? Recommend the SDT consider removing the language regarding “work plan flexibility” as this may suggest and impose an unnecessary compliance burden on Registered Entities and Auditors.
	Response: Thank you for your comments. The SDT views Major Storms in the list of examples differently than in Footnote 2. The example has more to do with schedules being revised as a result of a major storm while Footnote 2 refers to issues of sustained outages caused by circumstanses beyond the control of the Transmission Owner, and excepting resulting violations to the standard. **The SDT feels it is important to track and document changes in the work plan to insure rescheduled work is completed at some later date. Work plan flexibility through modification to the work plan is critical and must be recognized so that the Transmission Owner can propertly plan and revise work schedules when necessary.**		
11	Xcel Energy	No	What exactly does complete an annual work plan mean? It infers that an annual work plan must be developed/documented and executed. If this is the case, then clearly state as such.In general, R6 & R7 go against the grain of the results based standard concept. R1 already established that the Transmission Owner cannot have encroachment. R3 requires annual inspection (essentially establishing the plan). Why replicate in R6 & R7, it does not seem to serve any useful purpose.
	Response: Thank you for your comments. As stated in the Rationale, “This requirement sets the expectations that the work identified in the annual work plan will be completed as planned.” Because the		

	Organization	Yes or No	Question 5 Comment
	work plan is recurring in nature, a new work plan must be developed each year to state work planned for that period. This requirement directly supports Requirement 3 which calls for a documented vegetation management approach to prevent MVCD encroachments.		
12	Allegheny Power	Yes	
13	American Transmission Company	Yes	
14	Arizona Public Service Company	Yes	
15	BGE Forestry Management	Yes	
16	Bonneville Power Administration	Yes	
17	Central Maine Power Company, Iberdrola USA	Yes	
18	Consolidated Edison Company of New York Inc	Yes	
19	Consumers Energy Company	Yes	
20	FPL Corporate Compliance	Yes	
21	Dominion	Yes	

	Organization	Yes or No	Question 5 Comment
22	Duke Energy	Yes	
23	Entergy Services	Yes	
24	Exelon	Yes	
25	FirstEnergy	Yes	
26	Great River Energy	Yes	
27	Hydro One	Yes	
28	Idaho Power	Yes	
29	Idaho Power Company	Yes	
30	ITC Transmission	Yes	
31	Manitoba Hydro	Yes	
32	Northeast Power Coordinating Council	Yes	
33	Northeast Utilities	Yes	
34	Orange and Rockland Utilities, Inc.	Yes	
35	Pepco Holdings, Inc - Affiliates	Yes	
36	PNM	Yes	

	Organization	Yes or No	Question 5 Comment
37	PPL Electric Utilities	Yes	
38	Progress Energy	Yes	
39	South Carolina and Gas	Yes	
40	Tri-State Generation & Transmission	Yes	
41	Western Electricity Coordinating Council	Yes	annual vegetation management plans must have some flexibility. If the TO has the authority to create the plan they should have the authority to modify the plan. The key point is that changes, particularly delays to planned work would have to be approved. Do not believe “decreases in funding” should be listed as a valid reason for modification of work plan related to a reliability standard.From an enforcement viewpoint, there is ambiguity or perceived ambiguity in “provided they do not put the transmission system at risk of a vegetation encroachment.” Provided the potential that there may never be a self-report addressing this violation.
	Response: Thank you for your comments. The SDT agrees the plan needs flexibility and the Transmission Owner has authority for plan oversite. No approval for changes is called for in the requirement, but documentation is required to note the change. **The SDT reviewed the Funding Adjustment example for R7 and feels this is a valid reason for modifying the Annual Plan keeping in mind that a modification must not place the transmission system at risk of vegetation encroachment into the MVCD.**		
42	Southern California Edison Company	Yes	SCE agrees with the revisions to R7, but notes the some minor edits to the text are still needed.
	Response: Thank you for your comments. The SDT felt the language was appropriate.		
43	MRO’s NERC Standards Review Subcommittee (nsrs)	Yes	The NSRS has issue with the word “may” (and its components along with the associated bulleted points) and recommends that it is removed and placed in the rational box.

	Organization	Yes or No	Question 5 Comment
	Response: Thank you for your comments. The SDT believes the requirement as written is needed to insure flexibility of work plan.		
44	BC Hydro	Yes	The requirement as currently worded, seems to assume but does not explicitly state that a utility must prepare and document an annual vegetation work plan and document in some manner any modifications to that work plan as they occur. The work plan change documentation should include any risks of work deferral and mitigation plans to address those risks if there are any.
	Response: Thank you for your comments. Per the SDT, developing the annual work plan is an understood requirement in order for the TO to complete the work plan. Thus, a requirement to develop the plan is not needed. R3 specifies the processes, procedures and/or specifications that are utilized by a TO to prevent an encroachment of the MVCD. This "Competency Based" requirement sets the core foundation that a TO will utilize to develop their annual work plan. **The lack of a violation of R1 or R2 is the outcome of the ideal work plan. It is the responsibility of the TO to manage the quality of the work plan and mitigate any risk to the system associated with modifications to the work plan.**		
45	Tampa Electric Company	Yes	These changes add greater clarity, as well as real world examples, to this standard.
	Response: Thank you for your comments.		

6. In response to comments received that requirement R1/R2 may not adequately protect the transmission conductors under all conditions of sag and sway, the SDT drafted alternate language for the industry to provide feedback. The SDT did not opt to incorporate this language into "Draft 4" until further comment was solicited from industry. Which do you prefer? Please comment on your choice in the comment box below:

*"**Alternate R1/R2.** Each Transmission Owner shall manage the floor of its Active Transmission Line ROW in accordance to one of the following at all times:*

A) A fixed maximum vegetation height of 15 feet from the ground at the mid-half of the span and 20 feet in the outside quarters of the span, or,

B) A calculated maximum vegetation height that is the difference between the minimum conductor height at "max sag" minus MVCD minus cycle growth, or,

C) A calculated minimum vegetation to conductor clearance that is the sum of "max sag" in the span plus MVCD plus cycle growth, or,

D) A value determined by the Transmission Owner to provide a separation between the conductor and the vegetation that is comparable to options A, B, or C.

E) Any alternative approach that ensures no encroachment occurs within MVCD, considering the sag and sway of the conductor throughout its operating range under rated conditions.

F) A value to provide a separation between the conductor and the vegetation that is the sum of MVCD, and a value that considers the sag and sway of the conductor throughout its operating range under rated conditions plus 10 feet."

NOTE: The SDT suggests similar language as found in the posted draft for measures M1/M2 may be appropriate with this Alternate R1/R2.

Summary Consideration:

Of 45 respondents, there are 4 abstentions (expressed no preference for Draft or Alternate), 16 (two of which appear to be from the same company) are in agreement (that Alternate Language is preferred), and 25 are in disagreement (that Alternate is preferable, liking Draft language better).

The major comment issue raised is:

1. The only real issue raised in the comments by the 41 respondents that had a preference was that of the style of Requirement language appropriate for an RBS standard. Both groups agreed that either the Draft or Alternate language addressed the root requirement(s). In fact, respondents in both groups indicated that Option E

of the Alternate language was in essence the Draft language. (And of those in Alternate group that discussed the 6 options, E was the clear favorite, receiving five (5) mentions with A and C only receiving one (1).)

However, those that preferred the Alternate language cited that written in the form proposed by the Alternate language, the Requirements R1/R2 would provide much more flexibility and two respondents even cited that the Alternate allowed Transmission Owners to specify their own clearances.

For those voting for the Draft language (the majority), the most common reason cited was Draft language was less prescriptive. The second most common reason cited was that the Alternate Language would be confusing. And a couple commenters in this group opined that the Alternate language appeared to be “fill-in-the-blanks” language.

The VM SDT consideration for the major comment issue is:

1. **Based on the “vote” the team will retain the Draft language. Also, Option E was cited most often by the Alternate group as the most desirable of the options and is in fact essentially the Draft language. The SDT was additionally swayed by the comments about confusion and fill-in-the-blanks as two overriding premises behind the standards should be clarity and acceptance by FERC.**

A minor comment issue is:

1. **Commenters offered several minor wording changes to the Draft language.**

The VM SDT consideration for the minor comment issue is:

1. **The team has incorporated some of these minor wording changes and rejected others when the change was found to introduce other problems.**

	Organization	Yes or No	Question 6 Comment
1	MWDSC (METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA)		

	Organization	Yes or No	Question 6 Comment
2	Progress Energy		
3	South Carolina and Gas		
4	Arizona Public Service Company		Neither version is acceptable ANSI-A300 part 7 should be included here. Having set distances will give federal agencies the ability to minimize a utilities TVMP.
	Response: The SDT thanks you for your comments. The team appreciates your concern about federal agencies and other landowners' interpretation of the Requirement to impede vegetation management but is not swayed that the language currently in the Draft version suffers from a set distance specification as you cited.		
5	Bonneville Power Administration	Alternate version of R1/R2	
6	Central Maine Power Company, Iberdrola USA	Alternate version of R1/R2	
7	PNM	Alternate version of R1/R2	
8	GDS Associates	Alternate version of R1/R2	- E) seem more appropriate. The alternate R1/R2 standard requirements shall reduce the number of possibilities and simplify the criteria towards the design / operating conditions and additional standards ought to be considered in concert with current stan
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.		
9	Allegheny Power	Alternate version of R1/R2	Allegheny Power prefers the alternate version.
	The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which		

	Organization	Yes or No	Question 6 Comment
	may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.		
10	PPL Electric Utilities	Alternate version of R1/R2	Alternate C provides assurances that growth rates, maintenance cycle, and max-sag are taken into consideration.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft because the SDT believes it already addresses the provisions you state, i.e. growth rates, maintenance cycle, etc.		
11	Hydro One	Alternate version of R1/R2	Alternate Version E would allow a Transmission Owner to use an approach consistent with the current version of FAC-003 by defining a minimum clearance distance and a vegetation management clearance distance. This approach has met the objectives of FAC-003 since 2006. Use of version E would change the standard from a prescriptive approach to a Transmission Owner defined approach. In addition, Alternate Version E is preferred as it allows for variations based on differences in conductor heights, topography and other situations where a set height is not necessarily required in all instances and allows for the utility to determine the maximum heights of vegetation without performing detailed calculations of what the maximum heights must be along the various distances within each conductor span. If the utility is tasked with managing the vegetation to ensure no encroachments into the MVCD then it should be up to the individual utility how best to determine its management strategies that incorporate the determination of maximum vegetation heights in each section on its system.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.		
12	Northeast Power Coordinating	Alternate version of R1/R2	Alternate Version E would allow a Transmission Owner to use an approach consistent with the current version of FAC-003 by defining a

	Organization	Yes or No	Question 6 Comment
	Council		minimum clearance distance and a vegetation management clearance distance. This approach has met the objectives of FAC-003 since 2006. Use of version E would change the standard from a prescriptive approach to a Transmission Owner defined approach. In addition, Alternate Version E is preferred as it allows for variations based on differences in conductor heights, topography and other situations where a set height is not necessarily required in all instances and allows for the utility to determine the maximum heights of vegetation without performing detailed calculations of what the maximum heights must be along the various distances within each conductor span. If the utility is tasked with managing the vegetation to ensure no encroachments into the MVCD then it should be up to the individual utility how best to determine its management strategies that incorporate the determination of maximum vegetation heights in each section on its system.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.		
13	Idaho Power	Alternate version of R1/R2	Alternative R1/R2 allows the utility to maintain adequate clearances with their preferred approach.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.		
14	FirstEnergy	Alternate version of R1/R2	Although we agree with the alternate version of R1/R2, we have the following comments:1. We assume that R1 and R2 will be written similar to the current proposal with regard to IROL (High VRF) and non-IROL (Medium VRF) transmission lines, respectively. This should be clear after changes have been made to the standard before the final ballot.2. Although the SDT states that it "suggests similar language as found in the posted draft for measures M1/M2 may be appropriate with this alternate R1/R2", we are not clear how these measures will be written and would like to see a draft of the measures so we can review and

	Organization	Yes or No	Question 6 Comment
			comment.3. The alternate requirements appear to be "planning" in nature instead of "real-time"; we assume the intention of the SDT was the latter. Therefore the requirements should be revised with language that is "real-time" in nature.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.		
15	BGE Forestry Management	Alternate version of R1/R2	BGE believes R1/R2 should contain language that ensures that vegetation is manage taking into account sag and sway throughout the conductors operating range as the alternate language above outlines. The six options proposed allows the Transmission Owner the flexability needed to manage the active ROW a varity of ways and at the same time ensures the reliable operation the Bulk Electric System with respect to vegetation.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft because the SDT believes it already addresses the provisions you state, i.e. sag and sway.		
16	Idaho Power Company	Alternate version of R1/R2	I think this gives us more flexibility to maintain our clearances.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.		
17	Northeast Utilities	Alternate version of R1/R2	Option E above is preferred as it allows for variations based on differences in conductor heights, topography and other situations where a set height is not necessarily required in all instances and allows for the utility to determine the maximum heights of vegetation without

	Organization	Yes or No	Question 6 Comment
			performing detailed calculations of what the maximum heights must be along the various distances within each conductor span. If the utility is tasked with managing the vegetation to ensure no encroachments into the MVCD then it should be up to the individual utility how best to determine its management strategies that incorporate the determination of maximum vegetation heights in each section on its system.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.		
18	Consumers Energy Company	Alternate version of R1/R2	Prefer Alternative A
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft.		
19	Kansas City Power & Light	Alternate version of R1/R2	Prefer Alternative E from the list above. Please clarify the meaning of sway in Alternative E. Is that wind blowout?
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft. Sway is synonymous with wind blowout in Alternative E. Please refer to the Technical Reference document for further clarification on this issue.		
20	Southern California Edison Company	Alternate version of R1/R2	SCE prefers the operational flexibility provided by the alternate version of R1/R2. We also note that dating back to development of FAC-003-1 and related comment periods, Transmission Owners have repeatedly stated that a “one-size-fits-all” TVMP is not viable or reasonable.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which may simplify the application by Transmission Owners but is concerned that a majority of		

	Organization	Yes or No	Question 6 Comment
	commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current Draft. The SDT completely agrees with your comment about the 'one-size-fits-all' issue. The SDT has struggled with the proper wording that would allow each Transmission Owner the flexibility necessary to minimize the risk of vegetation outages while adapting to their unique vegetation challenges in a cost-effective-to-consumers manner. The SDT would encourage you, in future comment periods, to offer specific wording that will address the deficiencies you identified and what persuaded you to choose the Alternate version of R1/R2 as the preferred version.		
21	Ameren	Draft 4 version of R1/R2	
22	Duke Energy	Draft 4 version of R1/R2	
23	Exelon	Draft 4 version of R1/R2	
24	Great River Energy	Draft 4 version of R1/R2	
25	ITC Transmission	Draft 4 version of R1/R2	
26	MidAmerican Energy	Draft 4 version of R1/R2	
27	Pepco Holdings, Inc - Affiliates	Draft 4 version of R1/R2	
28	Tri-State Generation & Transmission	Draft 4 version of R1/R2	
29	Xcel Energy	Draft 4 version of R1/R2	Any of the alternate versions would amplify or create issues between land owners and Transmission Owners and are contrary to concepts of Integrated Vegetation Management, in particular, best management practices.
	Response: The SDT thanks you for your comments. Based on the industry support for the Draft 4 language, the SDT		

	Organization	Yes or No	Question 6 Comment
	has opted to retain the language in the current draft, in part because of the confusion you cited.		
30	American Transmission Company	Draft 4 version of R1/R2	ATC feels that Draft 4 Version of R1/R2 is the preferred version. The Alternate version is too prescriptive and has little flexability.
	Response: The SDT thanks you for your comments. Based on the industry support for the Draft 4 language, the SDT has opted to retain the language in the current draft; in part because of the prescriptive nature of the Alternate versions that you mentioned as well as it being noted as confusing.		
31	CenterPoint Energy	Draft 4 version of R1/R2	CenterPoint Energy does not believe a performance based requirement should be this prescriptive. However, if the majority of industry commenters agree with the SDT's approach, CenterPoint Energy has several concerns. The terminology, "operating within Rating and Rated Electrical Operating Conditions" is sufficiently definitive. There is no need to be more prescriptive. Alternate R1/R2 (E) is already similar to the Draft 4 wording. Of the two alternative, we recommend keeping the Draft 4 wording as is; however, we recommend moving the applicability of transmission line ratings to the Applicability section of the Standard as "4.5 Other: The Standard does not apply to any occurrence, non-occurrence, or other set of circumstances that are beyond the Rating and Rated Electrical Operating Conditions of the Facilities defined in 4.2." These conditions should be applicable to all elements and requirements of the Standard just as the force majeure statement does.
	Response: The SDT thanks you for your comments. Based on the industry support for the Draft 4 language, the SDT has opted to retain the language in the current draft, in part because of the prescriptive nature you mentioned as well as it being noted as confusing. The SDT has considered your excellent suggestion about the Applicability Section. However, after extensive discussion, the SDT opted not to add the language in the Applicability Section as the NERC framework for Applicability Sections seems to guide against it.		
32	Consolidated Edison Company of New York Inc	Draft 4 version of R1/R2	Consolidated Edison Company of New York, Inc prefers the Draft 4 version. The wording in the VSLs should be modified for both Requirements to include the phrase 'manage vegetation'. The phrase 'manage vegetation' requires a utility to take specific action to prevent encroachments/outages.

	Organization	Yes or No	Question 6 Comment
	Response: The SDT thanks you for your comments. The SDT has considered your excellent suggestion about the VSLs and decided to change the Requirements in the manner you describe.		
33	Entergy Services	Draft 4 version of R1/R2	Draft 4 is acceptable, but if alternate language is chosen, it should be similar to option E, keeping the determination simple and with as few variables for interpretation as necessary.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which could have simplified the application by Transmission Owners but is concerned that a majority of commenters find the alternate language confusing and potentially to be fill-in-the-blanks. Therefore the team has decided to retain the language in the current draft.		
34	Western Electricity Coordinating Council	Draft 4 version of R1/R2	Draft 4 should be sufficient. If industry believes MVCD is not adequate then the tables for MVCD should be modified to account for sag and sway.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which could have simplified the application by Transmission Owners but is concerned that a majority of commenters find the Alternate language confusing and potentially to be fill-in-the-blanks. Therefore the team has decided to retain the language in the current draft. The SDT is convinced that the technically defensible MVCD is adequate but appreciates the helpful suggestion nonetheless.		
35	Manitoba Hydro	Draft 4 version of R1/R2	I would suggest adding verbage to the draft 4 version to explicitly include the sag and sway of the conductor to the concept of "operating within rating and electrical operating condition"
	Response: The SDT thanks you for your comments. Based on the support for the Draft 4 language, the SDT has opted to retain the language in the current draft, in part because of the prescriptive nature you mentioned as well as it being noted as confusing. The SDT has considered your thoughtful and helpful suggestion about the explicit language which could be added to the Requirement to make it stand-alone and not rely on the Technical Reference document. The SDT, however, decided not to add the suggested verbiage because the team felt that the Rationale Box addressed this issue and the Requirement, if modified, would become somewhat confusing.		
36	MRO's NERC Standards Review	Draft 4 version of R1/R2	It is the NSRS's opinion that that the requirement as currently written in version 4 is consistent with the intent of a standard; i.e. stating what is

	Organization	Yes or No	Question 6 Comment
	Subcommittee (nsrs)		required as opposed to stating how to achieve what is required.
	Response: The SDT thanks you for your comments. Based on the support for the Draft 4 language, the SDT has opted to retain the language in the current draft, in part because of the prescriptive nature of the alternate that you cited, as well as it being noted as confusing.		
37	NERC Staff	Draft 4 version of R1/R2	NERC staff supports the Draft 4 version. The six options listed in the alternative version of R1/R2 do not seem manageable from a utility perspective. But while staff prefers the existing language, it continues to emphasize that fall-ins from outside the ROW can impact the line and need to be taken into consideration.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offered many choices which may simplify the application by Transmission Owners but is concerned that a majority of commenters, including you, find the alternate language confusing and some even cite that it may potentially be fill-in-the-blanks. Therefore, the team has decided to retain the language in the current draft. Although the SDT understands that fall ins from off-ROW trees can negatively impact the lines and a sound TVMP would include a program to address these potential issues, it is not appropriate that off-ROW trees be included in a NERC Standard. This is mainly because a utility does not have the rights to remove private trees and the process to acquire rights to remove these trees is quite arduous and costly.		
38	Orange and Rockland Utilities, Inc.	Draft 4 version of R1/R2	Orange and Rockland Utilities, Inc prefers the Draft 4 version. The wording in the VSLs should be modified for both Requirements to include the phrase 'manage vegetation.' The phrase 'manage vegetation' requires a utility to take specific action to prevent encroachments/outages.
	Response: The SDT thanks you for your comments. The SDT has considered your excellent suggestion about the VSLs and decided to change the Requirements in the manner you describe.		
39	Tampa Electric Company	Draft 4 version of R1/R2	Quite frankly, the alternatives listed above, or for that matter any other vegetation managment options, should be establised by the utility. The goals in R1 & R2 are very clear. The alternatives listed above will create a double or triple standard of vegetation clearance for each different type of Transmission construction.

	Organization	Yes or No	Question 6 Comment
	Response: The SDT thanks you for your comments. Based on the support for the Draft 4 language, the SDT has opted to retain the language in the current draft, in part because of the confusion you mentioned.		
40	Dominion	Draft 4 version of R1/R2	The alternate language proposed above suggests that methodologies typically incorporated into processes, procedures, or specifications (as required by R3) should also be included into performance-based requirements R1 and R2. The incorporation of this language into R1 and R2 would change these requirements from performance-based requirements to hybrid performance/competency-based requirements.The intent of R1 and R2 is to define a failure to prevent encroachment into the MVCD. Ensuring that a TO's processes, procedures, or specifications demonstrate adequate means of protecting conductors falls under R3, which incorporates transmission conductor and vegetation dynamics and interrelationships. Therefore, methodologies employed to manage the floor of active transmission ROW should be incorporated into the documentation required by R3 and proof that vegetation was managed in accordance with processes, procedures, or specifications to prevent encroachment into the MVCD will be demonstrated by compliance with R1 and R2.
	Response: The SDT thanks you for your comments. Based on the support for the Draft 4 language, the SDT has opted to retain the language in the current draft, in part because it was less prescriptive and more performance-based as you mentioned.		
41	FPL Corporate Compliance	Draft 4 version of R1/R2	The alternative is a fill in the blanks requirement.
	Response: The SDT thanks you for your comments. The SDT recognizes that the alternate language offers many choices which could have simplified the application by Transmission Owners but is concerned that a majority of commenters find the Alternate language confusing and, as you cite, potentially to be fill-in-the-blanks.		
42	BC Hydro	Draft 4 version of R1/R2	The alternatives above are too prescriptive. A utility should set a preferred maintenance distance (i.e. clearance 1 in FAC-003-1) as routine expectation and outline mitigation strategies as required in areas where clearance 1 distances cannot be met to ensure that MVCD distances are not encroached upon. Given the various line design

	Organization	Yes or No	Question 6 Comment
			standards, it is the utility that must define those clearances and margins of error based on engineering standards and the types of vegetation and growth rates present in their operating area.
	Response: The SDT thanks you for your comments. Based on the support for the Draft 4 language, the SDT has opted to retain the language in the current draft, in part because it was less prescriptive as you cited.		
43	Western Area Power Administration	Draft 4 version of R1/R2	The current language of Draft 4 is the most flexible and offers industry the best opportunity for executing a cost effective and efficient program.
	Response: The SDT thanks you for your comments. The SDT has struggled with wording to try to allow each Transmission Owner the flexibility necessary to minimize the risk of vegetation outages while adapting to their unique vegetation challenges in a cost-effective-to-consumers manner. Based on the support for the Draft 4 language, the SDT has opted to retain the language in the current draft, because the SDT believes it achieves the goal you cited.		
44	The United Illuminating Company	Draft 4 version of R1/R2	UI prefers the draft language because we believe the intent of R1/R2 is to capture the actual occurrence of a vegetation related interruption or encroachment of vegetaion into the MVCD based on actual conditions.
	Response: The SDT thanks you for your comments. Based on the support for the Draft 4 language, the SDT has opted to retain the language in the current draft. As you describe, this language captures the true intent of the Requirements in the least confusing and prescriptive manner, as confirmed by other comments received.		
45	Southern Company Transmission	Draft 4 version of R1/R2	We feel the alternative language is too confusing. Does a utility choose one option from the list and expect it to cover all situations, or can the utility pick one option from the list and apply that option to one span, and then another option for the next span. The proposed alternate verbiage makes no distinction as to when options can or cannot be utilized. The language in Draft 4 seems to cover the various scenarios a utility will face in its vegetation management program while giving the utility the flexibility necessary to address these situations in an appropriate manner.
	Response: The SDT thanks you for your comments. Based on the support for the Draft 4 language, the SDT has		

	Organization	Yes or No	Question 6 Comment
	opted to retain the language in the current draft, in part because of the confusion you cited.		

7. The drafting team and NERC staff disagree on an appropriate set of VSLs for Requirements R1 and R2 and the Standards Committee has directed that both sets of VSLs be posted for stakeholder comments. Which set of proposed VSLs best supports NERC's VSL Criteria?

Summary Consideration:

Of 45 respondents, 6 chose neither set of VSLs, 8 disagreed with the SDT, and 31 agreed with the SDT.

Among those who disagreed with the SDT the major comment issues raised are:

1. **VSLs are too low and they do not seem to differentiate between various levels of compliance. Commenter is concerned that the difference between an encroachment that leads to an outage and one that does not is based on nothing but luck.**
2. **The NERC staff set requires a higher degree of accountability.**

The VM SDT considerations for the major comment issues are:

1. **The VM SDT proposed a set of four VSLs to reflect the wide range of non-compliances to these requirements. The NERC staff on the other hand view the outcomes as narrow.**

   The comment that SDT VSLs are "too low" lacks context. The commenter does not offer a frame of reference in rendering its opinion of "too low".

   The comment about luck is without basis. The SDT asserts that vegetation related outages are directly related to the encroachment mechanism, i.e., how vegetation contacts conductors.

   The differing perspectives do not appear to be reconcilable. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.
2. **The VM SDT believes the VSLs are precisely set to reflect the degree of accountability that best matches the level of non-compliance. Grow-in's are classified in the highest level of violation severity precisely because it is indicative of the lowest quality of performance and therefore the entity must be held to the highest degree of accountability in that case.**

Some minor comment issues are:

1. **Criteria will be probably best represented by a mix of the two VSLs.**

2. Neither set is correct.

The VM SDT considerations for the minor comment issues are:

1. The VM SDT proposed a set of four VSLs to reflect the wide range of non-compliances to these requirements. The NERC staff on the other hand view the outcomes as very narrow. The differing perspectives do not appear to be reconcilable through a hybrid approach as you suggested.

2. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.

	Organization	Yes or No	Question 7 Comment
1	MWDSC (METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA)		
2	Progress Energy		
3	Western Electricity Coordinating Council		
4	GDS Associates		Criteria will be probably best represented by a mix of the two VSLs as follows:- Keep the Lower and Moderate VSLs from SDT with both absent Sustained Outage. Add the fall-in as specific encroachment to the Lower VSL and grow-in as specific encroachment to the Moderate VSL- Keep the High / Severe VSLs from NERC
	Response: Thank you for your comment. The VM SDT proposed a set of four VSLs to reflect the wide range of non-compliances to these requirements. The NERC staff on the other hand view the outcomes as very narrow. The		

	Organization	Yes or No	Question 7 Comment
	differing perspectives do not appear to be reconcilable through a hybrid approach as you suggested.		
5	Pepco Holdings, Inc - Affiliates		Neither set is correct. The SDT proposed VSLs do not identify encroachment into the MVCD of a line not in an IROL or Major WECC transfer path, and the NERC Staff proposed VSLs do not do not identify encroachment into the MVCD of a line that is in an IROL or Major WECC transfer path
	Response: Thank you for your comment. Measures M1 & M2 along with The Rationale boxes for R1 & R2 can be used to understand what is meant by the MVCD. The Rational Box States: **"The MVCD is a calculated minimum distance stated in feet (meters) to prevent spark-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method."**		
6	CenterPoint Energy		Neither. However, we recommend that High or Severe violations be based only on Sustained Outages experienced and the reliability importance of the transmission line. Any process or procedure based requirement, if kept within the Standard, should have a Lower or Moderate designation based on the utilities intent or capability to comply with the Requirement.
	Response: Thank you for your comment. The VM SDT proposed a set of four VSLs to reflect the wide range of non-compliances to these requirements. The NERC staff on the other hand view the outcomes as very narrow. The differing perspectives do not appear to be reconcilable. Your suggestion is appreciated, however the VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
7	Consumers Energy Company	VSLs proposed by NERC staff	
8	Idaho Power Company	VSLs proposed by NERC staff	
9	FPL Corporate Compliance	VSLs proposed by NERC staff	Again the drafting team is trying to control the terms of a requirement by using the compliance elements. FPL agrees there is a direct link between vegetation growing in to conductors from below has a direct correlation to cascading events and fall-in and blow-in outages are no

	Organization	Yes or No	Question 7 Comment
			more incidental than a cross arm failure to a cascading event. These components should be handled in the requirements and not in the compliance element.
	Response: Thank you for your comment. The VM SDT proposed a set of four VSLs to reflect the wide range of non-compliances to these requirements. The NERC staff on the other hand view the outcomes as very narrow. The differing perspectives do not appear to be reconcilable. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
10	Dominion	VSLs proposed by NERC staff	As all parts of R1/R2 seem to contribute equally to the intent of the requirement - shall manage vegetation to prevent encroachment that could result in a Sustained Outage - NERC's proposed VSLs best address noncompliance with the requirements.
	Response: Thank you for your comment. The VM SDT proposed a set of four VSLs to reflect the wide range of non-compliances to these requirements. The NERC staff on the other hand view the outcomes as very narrow. The differing perspectives do not appear to be reconcilable. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
11	NERC Staff	VSLs proposed by NERC staff	NERC staff supports the VSLs proposed by NERC staff. The SDT's VSLs are too low, and they do not seem to differentiate between various levels of compliance. Still, staff is concerned that the difference between an encroachment that leads to an outage and one that does not is based on nothing but luck.
	Response: Thank you for your comment. The VM SDT proposed a set of four VSLs to reflect the wide range of non-compliances to these requirements. The NERC staff on the other hand view the outcomes as very narrow. **The comment that SDT VSLs are "too low" lacks context. The commenter does not offer a frame of reference in rendering its opinion of "too low".** **The comment about luck is without basis. The MVCD distances are conservative and it is quite possible to be well within the MVCD and not have a flashover or an outage. This is based on physics, not "luck". Prudent inspection frequencies and a good imminent threat notification process are 2 things that could prevent encroachments from becoming an outage. Stating that it is only dependent on luck does not give proper credit to prudent operations.** **The SDT has revised R1 and R2 to clarify that the level of maintenance is the primary focus of this requirement that must be attained to be compliant. The VM SDT feels these changes will ensure congruence between the requirements**		

	Organization	Yes or No	Question 7 Comment
	and the VSL.		
12	Arizona Public Service Company	VSLs proposed by NERC staff	Requires a higher degree of accountability as it should be.
	Response: Thank you for your comment. The VM SDT proposed a set of four VSLs to reflect the wide range of non-compliances to these requirements. The VM SDT believes the VSLs are precisely set to reflect the degree of accountability that best matches the level of non-compliance. A grow-in is classified in the highest level of violation severity precisely because it is indicative of the lowest quality of performance. Therefore, the entity must be held to the highest degree of accountability for any maintenance failure that leads to a grow-in. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
13	Idaho Power	VSLs proposed by NERC staff	Seems like there should be a lesser severity level for violations for R3-R7.
	Response: Thank you for your comment. This question asks for feedback on the VSLs assigned to R1 and R2.		
14	The United Illuminating Company	VSLs proposed by NERC staff	United Illuminating agrees with NERC Staff that the Requirement is to prevent encroachment of any kind. Differentiating between fall-in and grow-in is of no consequence to the intent of the requirement.
	Response: Thank you for your comment. Please refer to the SDT response to NERC on this question.		
15	Allegheny Power	VSLs proposed by the VM SDT	
16	Ameren	VSLs proposed by the VM SDT	
17	BGE Forestry Management	VSLs proposed by the VM SDT	
18	Bonneville Power Administration	VSLs proposed by the VM SDT	
19	Duke Energy	VSLs proposed by the VM SDT	

	Organization	Yes or No	Question 7 Comment
20	Exelon	VSLs proposed by the VM SDT	
21	ITC Transmission	VSLs proposed by the VM SDT	
22	Manitoba Hydro	VSLs proposed by the VM SDT	
23	MidAmerican Energy	VSLs proposed by the VM SDT	
24	MRO's NERC Standards Review Subcommittee (nsrs)	VSLs proposed by the VM SDT	
25	Northeast Utilities	VSLs proposed by the VM SDT	
26	PPL Electric Utilities	VSLs proposed by the VM SDT	
27	South Carolina and Gas	VSLs proposed by the VM SDT	
28	Tri-State Generation & Transmission	VSLs proposed by the VM SDT	
29	Xcel Energy	VSLs proposed by the VM SDT	
30	Central Maine Power Company, Iberdrola USA	VSLs proposed by the VM SDT	Agrees with SDT that violation risk factors must be ranked in accordance with impact on the bulk delivery system.
	Response: Thank you for your comment.		

	Organization	Yes or No	Question 7 Comment
31	Kansas City Power & Light	VSLs proposed by the VM SDT	Although the Drafting Team is favored here, it makes little sense in the NERC Staff VSL to have an encroachment with no sustained outage as a HIGH VSL. No compromise of the real-time reliability of the bulk electric system occurred. How could that be a HIGH? If it is determined to use the VSLs proposed by NERC Staff, it is recommended to change the HIGH VSL to LOWER.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
32	American Transmission Company	VSLs proposed by the VM SDT	ATC believes the VSLs proposed by the VM SDT best supports the NERC's VSL Criteria. The NERC Staff VSLs do not allow for Lower or Moderate VSLs which recognizes significant value as nearly meeting the intent of the requirement. Furthermore, it does not allow for encroachment where absent a sustained outage. Every encroachment in real time would not go directly to a "High" VSL where performance has limited value.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
33	FirstEnergy	VSLs proposed by the VM SDT	FE supports the VSL proposed by the SDT. We believe these have been developed in accordance with the FERC approved VSL guidelines and represent the appropriate violation levels for situations of varying probabilities. History has proven the grow-ins are the biggest cause of vegetation contact issues, and fall-ins and blowing together vegetation are very hard to predict and control and should be at lower violation levels. Although we believe that an encroachment into the MVCD that causes no system disturbance should not be penalized if an entity takes immediate action to restore the minimum clearance, the assignment of a Lower VSL is appropriate. We believe that the NERC staff opinion that this situation warrants a High VSL does not demonstrate thorough rationalization because it fails to consider the consequences that would place a severe monetary penalty on an entity for a situation that did not cause a fault, outage, or cascade of the BES.Furthermore, it is clear

	Organization	Yes or No	Question 7 Comment
			from the bullet points under R1 and R2 of the proposed standard language that the SDT intended that an encroachment with a sustained outage is different than and encroachment without a sustained outage otherwise they would not have specified the bulleted situations in detail. Had the SDT intended for there to be only two violation severity levels they would have only specified two bullet items: an encroachment with a sustained outage and an encroachment without a sustained outage. The requirements are the only tools the drafting team has to specify its intent in this area and the approach they used is reasonable to provide these levels of differentiation.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
34	Great River Energy	VSLs proposed by the VM SDT	GRE prefers the Drafting Team's VSLs over the VSLs written by the NERC staff. The VSLs that were written by the SDT appear to be clearer and less subjective as opposed to the VSLs that were written by NERC staff. The VSLs written by the NERC staff came across as being less clear and more subjective.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
35	Southern California Edison Company	VSLs proposed by the VM SDT	SCE agrees with the SDT's rationale and proposals for VSL Criteria.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
36	Tampa Electric Company	VSLs proposed by the VM SDT	Tampa Electric agrees with the SDT statement ... "For example, not all encroachments lead to Sustained Outages." As such, we agree, a lower level of VSL is appropriate. Tampa Electric also agrees with this statement " Moreover, there is an operational differentiation between a fall-in, blow-together or grow-in event. "Recommend the

	Organization	Yes or No	Question 7 Comment
			team examine the analytical rational for the following statements so as to better explain and clarify this issue to NERC. "A fall-in has never been known to cause a cascading outage. Therefore the team feels that a Lower VSL is appropriate. A blowing-together-caused fault is somewhat more egregious than a fall-in, as it has the potential for re-occurring and is therefore assigned a Higher VSL."
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
37	PNM	VSLs proposed by the VM SDT	The expectation is for perfection or zero encroachments at all times. It would be cost prohibitive to maintain the system under those rules. PNM recommends the VM SDT VSL's.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
38	BC Hydro	VSLs proposed by the VM SDT	The NERC staff recommendation is too restrictive and does not seem realistic in an operational sense. We do not agree that the standard should apply to outages from vegetation falling into the conductor from within the active transmission right of way. This normally would not occur except during storm events that would be excluded from this standard. It is operationally difficult to know precisely where the edge of the right of way is in all situations and under all conditions. Further, in clearing some sections to this degree, the utility could end up destabilizing what is currently a stable, windfirm edge and pose higher security risks to the transmission system from destabilizing the vegetation through excessive clearing. So this gets down to semantics of how a utility might define their active right of way corridor relative to the legal statutory right of way edge. The risk of fall into outages needs to be managed but as currently defined this is too absolute a requirement. Fall-into outage risks need to be mitigated but they have not been a key element of any cascading failure and are hard to prevent. Even if a right of way were cleared sufficiently wide to avoid a fall-into outage, there is always a risk of branches being blown into the conductors from sailing during higher winds (e.g. Douglas-fir branches have excellent airborne gliding

	Organization	Yes or No	Question 7 Comment
			abilities). The greatest risk is from grow-into outages or from conductors and vegetation being blown into one another within the active right of way. Therefore, we prefer the VSLs set by the VM standard development team.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
39	Consolidated Edison Company of New York Inc	VSLs proposed by the VM SDT	The wording in the VM STD VSLs should be modified to include whether or not the TO managed any vegetation on that particular line. A more severe VSL should be assigned to any encroachment or sustained outage that was caused as a result of a TO not performing any vegetation management activities on that line. For example, if vegetation management activities were completed on 80% or 90% of the line and additional work was in progress on the remainder of the line but an encroachement or sustained outage occurred on the spans that were scheduled to be done as part of the annual plan, the TO should be held accountable for this but at a lower severity level.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
40	Hydro One	VSLs proposed by the VM SDT	The wording in the VM STD VSLs should be modified to include whether or not the TO managed any vegetation on that particular line. A more severe VSL should be assigned to any encroachment or sustained outage that was caused as a result of a TO not performing any vegetation management activities on that line. For example, if vegetation management activities were completed on 80% or 90% of the line and additional work was in progress on the remainder of the line, but an encroachment or sustained outage occurred on the spans that were scheduled to be done as part of the annual plan, the TO should be held accountable for this but at a lower severity level.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		

	Organization	Yes or No	Question 7 Comment
41	Northeast Power Coordinating Council	VSLs proposed by the VM SDT	The wording in the VM STD VSLs should be modified to include whether or not the TO managed any vegetation on that particular line. A more severe VSL should be assigned to any encroachment or sustained outage that was caused as a result of a TO not performing any vegetation management activities on that line. For example, if vegetation management activities were completed on 80% or 90% of the line and additional work was in progress on the remainder of the line, but an encroachment or sustained outage occurred on the spans that were scheduled to be done as part of the annual plan, the TO should be held accountable for this but at a lower severity level.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
42	Orange and Rockland Utilities, Inc.	VSLs proposed by the VM SDT	The wording in the VM STD VSLs should be modified to include whether or not the TO managed any vegetation on that particular line. A more severe VSL should be assigned to any encroachment or sustained outage that was caused as a result of a TO not performing any vegetation management activities on that line. For example, if vegetation management activities were completed on 80% or 90% of the line and additional work was in progress on the remainder of the line but an encroachement or sustained outage occurred on the spans that were scheduled to be done as part of the annual plan, the TO should be held accountable for this but at a lower severity level.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
43	Entergy Services	VSLs proposed by the VM SDT	This gives the option to activate and follow the Imminent Threat Process if a breach of the MVCD is located and reported for isolated events absent a sustained outage. It gives the TO the opportunity to mitigate the issue when it is identified and corrected prior to experiencing an outage..
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		

	Organization	Yes or No	Question 7 Comment
44	Western Area Power Administration	VSLs proposed by the VM SDT	Unlike a “grow-in”, a “fall-in” or “blow-in” has never caused or contributed to a cascading outage. Further, the “zero tolerance” approach of this standard remains impractical and unreasonable. The gradated indicators of program performance associated with a “fall-in”, “blow-in” and “grow-in” offer some measure of reasonableness to the requirement.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		
45	Southern Company Transmission	VSLs proposed by the VM SDT	We support the SDT version of the VSLs. The version proposed by staff does not recognize the objective of FAC-003-2 which clearly states, “To improve the reliability of the electric Transmission system by preventing those outages that could lead to Cascading.” If a fall-in occurs in an afternoon thunder storm and investigation reveals the tree was on the right-of-way by one or two feet, staffs VSLs would treat this outage with the same severity as an outage where a fully loaded line in a heat wave sagged into unmaintained brush growing directly beneath the conductor. The first case would rarely, if ever, lead to cascading. The second case could easily lead to cascading. Staff’s VSLs seem to indicate a desire to “gold plate’ the system to insure 100% reliability, which will never be achieved absent of unlimited resources and with total disregard to cost.
	Response: Thank you for your comment. The VM SDT believes its VSL assignments follow the NERC VSL Guidelines and are technically valid.		

8. Is there anything that you have not addressed above regarding the draft FAC-003-2 Transmission Vegetation Management standard or the Technical Reference Document? If yes, please provide what you believe should be changed, added or deleted and the rationale for your proposal.

Summary Consideration:

Of the 45 respondents, 29 provided a comment. In general, there were no common themes and as such each comment was responded to individually. Of some note, two comments were especially lengthy and their well-considered responses are found below.

	Organization	Yes or No	Question 8 Comment
1	Great River Energy		
2	Allegheny Power	No	
3	Central Maine Power Company, Iberdrola USA	No	
4	Consumers Energy Company	No	
5	Duke Energy	No	
6	Exelon	No	
7	Manitoba Hydro	No	
8	Northeast Utilities	No	
9	Pepco Holdings, Inc - Affiliates	No	
10	PNM	No	

	Organization	Yes or No	Question 8 Comment
11	PPL Electric Utilities	No	
12	South Carolina and Gas	No	
13	Tri-State Generation & Transmission	No	
14	Western Area Power Administration	No	
15	Western Electricity Coordinating Council	No	
16	Tampa Electric Company	No	No additional comments
17	GDS Associates	Yes	- Effective Dates. Clarify effective dates in paragraphs 2 and 3. This should only be applicable to Canada as Standard are not mandatory and enforceable in the US unless further approved by FERC.- Exceptions. Regional Differences must be approved just li
	Response: The SDT thanks you for your response. NERC staff will review the effective date section and modify as necessary.		
18	Progress Energy	Yes	1) On p. 3 of the redline, the table of Effective Dates is struck out, but the key (listed as 1, 2, 3 below the table: “1. First calendar day...”) remains but now the numbers 1, 2, and 3 no longer refer to the table of Effective Dates as the table has been struck. 2) The first paragraph under “Exceptions” could be reworded to be clearer. As currently proposed, it states lines below 200kV become subject to the standard 12 months after the lines are designated as being subject to the standard, which is somewhat circular. We propose instead:”A line operated below 200kV becomes subject to this standard 12 months after the date the Planning Coordinator or WECC initially designates the line as an element of an IROL or as a Major WECC transfer path.”3)

	Organization	Yes or No	Question 8 Comment
			Applicability Section 4.2.4 says the standard does not apply to Facilities located in the fenced area of a switchyard. However, p. 8 in Section 5 Background says the standard does not apply to underground or submarine lines or line sections inside a station boundary. Two things should be addressed to make these consistent: "Facilities" is a NERC-defined term that includes more than just lines, and includes lines, generators, compensators, transformers, etc. Also, is the "station boundary" always defined by the fenced area? Any potential conflict due to this inconsistency should be resolved.4) In the redline of Draft 4, in R5 and M5, the word "interim" is struck through. However, the Rationale box says "....the intent is for the Transmission Owner to put interim measures in place..." The use of "interim" should be consistent between R5, M5 and the Rationale box.5) R6 requires the TO to perform Vegetation Inspections "at least once per calendar year". There could potentially be future interpretation requests that question whether "once per calendar year" means performance sometime during each year (i.e. 2010, 2011, etc.), or whether no more than 365 calendar days can elapse between inspections. The first interpretation could allow up to almost 2 years to elapse between inspections even when doing it "once per calendar year". This should be clarified.
	Response: The SDT thanks you for your response. NERC staff will review the effective date section and modify as necessary. Thank you for the wording, but overall industry consensus does not dictate a verbiage change. **Regarding station boundaries and underground lines, overall industry consensus is that line-based vegetation programs do not apply inside the station boundary. The SDT believes that "fence" is the best overall term for a station boundary.** **As to the use of "interim", the Rationale intends to provide clarifying text and there is no imperative that its language should be identical to the requirement verbiage. The SDT believes that the Rationale language properly conveys the intent.** **Regarding the inspection frequency, the SDT added an 18 month clause.**		
19	CenterPoint Energy	Yes	1. CenterPoint Energy believes the proposed FAC-003-2 is not a performance-based standard, despite being labeled as such, because it remains too focused on processes and procedures. CenterPoint Energy fails to see much difference in the approach from the current Standard.

	Organization	Yes or No	Question 8 Comment
			CenterPoint Energy believes a performance based requirement would provide performance criteria that an entity would be measured against. An example of a performance based requirement would be the following: R1. “Each Transmission Owner shall manage vegetation to prevent encroachment that results in no more than one (1) Sustained Outage per XXX circuit miles of applicable lines within any twelve (12) month period.” M1. Each Transmission Owner has evidence that it had in no more than one (1) Sustained Outage per XXX circuit miles of applicable lines within any twelve (12) month period. Examples of acceptable forms of evidence may include dated reports of vegetation-related Sustained Outages or dated attestations as to no vegetation-related Sustained Outages have occurred. However, if the majority of industry commenters agree with the SDT’s approach, CenterPoint Energy has the following additional concerns: 2. The phrases “active transmission line ROW” and “Active Transmission Line ROW” are no longer considered defined terms and should be deleted from the Standard along with footnote 2, the Compliance Section for Periodic Data Submittal as well as the Guidelines and Technical Basis. As found throughout the Standard, the phrase should be replaced with the common terms utilized in the Guidelines and Technical Basis section, “Transmission Owner’s transmission ROW as defined by easement, fee simple, or other legal rights”. 3. In the Background section fall-ins are characterized as “statistically intermittent” and “these types of events are highly unlikely to cause large-scale grid failures”. We agree and therefore recommend that fall-ins be excluded from the Requirements R1, R2, and Periodic Data Submittal of outages. 4. R4 should be deleted. R4 is related to processes and procedures and should be combined into R3. The result of not following the notification process or procedure is that a Sustained Outage may occur that would be

	Organization	Yes or No	Question 8 Comment
			captured by M1 and M2. The process and procedure would be measured by M3. 5. R5 and M5 contain the ambiguous phrase, "where a transmission line is put at risk due to the constraint". This phrase should be replaced with the more specific terminology in R1 and R2 as, "where a transmission line cannot perform within its Rating and Rated Electrical Operating Conditions due to the constraint" or as in R3 as "where a transmission line will be subjected to an encroachment into the MVCD due to the constraint". 6. For R6, the detailed rationale and studies used for the determination of the required one year inspection cycle should be included in the Guidelines and Technical Basis. The explanation provided in the Rationale that it is "based upon average growth rates across North America and on common utility practice" are unfounded and arbitrary without a specific reference to a North American study. 7. R7 contains the ambiguous phrase, "provided they do not put the transmission system at risk of a vegetation encroachment". This phrase should be replaced with the more specific terminology in the Rationale for R7 and Requirement R3 as "provided they do not allow encroachment of vegetation into the MVCD." 8. Just as the force majeure statement was moved to the Applicability section of the Standard, the exception for applicability beyond the Rating and Rated Electrical Operating Conditions should be included in the Applicability section as well. Currently, it is only included in R1, R2, and R3. It should be made clear that the other Requirements and Measurements ARE NOT applicable in situations beyond the Rating and Rated Electrical Operating Conditions. This is already discussed in the Guidelines and Technical Basis but not evident within the Standard. 9. The Periodic Data Submittal should be clarified to as to the specific conditions under which Sustained Outages are reported. The Applicability section includes the force majeure; however, other exclusions are not so evident. We recommend the wording be changed to include all applicable

	Organization	Yes or No	Question 8 Comment
			exclusions for added clarity. We recommend the following wording: "The Transmission Owner will submit a quarterly report to its Regional Entity, or Regional Entity's designee, identifying the Sustained Outages caused by vegetation, as defined in the categories below, of transmission lines operating within Rating and Rated Operating Conditions as determined by the Transmission Owner, exclusive of the force majeure conditions in Section 4.4, that include, as a minimum, the following." Also, the within the Categories listed, the phrases "active transmission line ROW" should be deleted and replaced with "Transmission Owner's transmission ROW as defined by easement, fee simple, or other legal rights". This places the determination of the width of the ROW for determination of fall-in violations clearly on the Transmission Owner and the within the limits of its legal rights to control the vegetation that has fallen into the line under R1 and R2 causing the submittal of a reportable sustained outage. 10. The Guidelines and Technical Basis and the Technical Reference with the Gallet Equation should be combined into one document as a supplement to the Standard to avoid duplication in wording and misinterpretation of context. 11. We agree that the Rationale test boxes should be deleted from the Standard and applicable explanatory text be included within the Guidelines and Technical Basis. 12. The Guidelines and Technical Basis should include the background and basis for 4.2.4 that excludes the Standard from applying to fenced substations. 13. The Guidelines and Technical Basis should contain more specific examples of violations of the Requirements and highlight specific exceptions related to vegetation related outages, especially fall-ins and force majeure exclusions. 14. The language in R6 refers to inspecting "transmission lines" and Table 1 for

	Organization	Yes or No	Question 8 Comment
			R6 refers to inspecting "ROW". Both areas should use consistent terminology. 15. In the Guidelines and Technical Basis section for R6, the reference to the VSL calculation units and the example units should be consistent-the example should use "circuit miles", not just "miles". 16. In general, the proposed FAC-003-2 has gone FAR beyond what was contemplated by the Commission in FERC Order 693 and equates to a total re-writing of the Standard for no apparent reason. The Commission's determination dealt with the following areas: (1) applicability; (2) inspection cycles; and (3) minimum clearances on National Forest Service lands. For instance in Paragraph 729, the Commission states, "As proposed in the NOPR, the Commission approves Reliability Standard FAC-003-1 with no proposed modification on the issue of clearances. The Commission reaffirms its interpretation that FAC-003-1 requires sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions...." Rewriting the minimum clearances introduced a new set of confusing definitions, and further burdens the Transmission Owners with new documentation requirements with little if any benefit when compared to the Clearance 2 concept in the existing Standard. A preferred approach should be to incorporate the following few items into the existing Standard FAC-003-1: (1) the RC versus the RRO; (2) the designation of a specific inspection frequency; (3) the Gallet equation; and

	Organization	Yes or No	Question 8 Comment
			(4) the applicability to National Forest Service lands.
	Response: 1) The SDT thanks you for your responses. The standard is intended to be a Results-based standard and includes requirements that are risk-based, competency-based and performance-based. The SDT and NERC staff feels that it represents a significant departure from previous versions. The SDT has considered “per-mile”-based metrics, but believes that FERC will not approve such a metric due to statutory constraints and its stated criteria for approval of a standard. 2) Based on your comment and others, the SDT has revised the definition of ROW in the NERC Glossary and removed Table 3. 3) While the SDT agrees that fall-ins are statistically intermittent, the fall-ins from inside the ROW are under the control of the TO and represent an erosion of reliability. 4) The SDT agrees that there is some logic in your proposal, but the SDT feels that all TOs should have a procedure that results in a defense-in-depth strategy as is in the current draft. 5) R5 applies in the longer-term Operations Planning time horizon, whereas R1 and R2 apply in real time. On the other hand, R3 is a competency-type of requirement that applies in the Long-Term Planning Time Horizon. 6) The SDT posed the question of inspection frequency to the overall industry in an earlier posting and received general consensus that a one-year interval would be appropriate but did add an 18 month clause. 7) R7 addresses shorter-term risks, whereas the language in R3 is about the prevention of encroachments in the wider long-term horizon. 8) The SDT has considered your suggestion about the applicability section; however, after extensive consideration, the SDT opted not to add the language you suggested since the NERC framework for the Applicability section guides against it. 9) Thank you. The SDT agrees and hereby adds “. . . except as excluded in Footnote 2” before “that includes.” Regarding your suggestion on active TLROW, the SDT changed the definition of ROW in the NERC Glossary. 10) The issue of combining these documents will be addressed by NERC as the results-based standard-		

	Organization	Yes or No	Question 8 Comment
	making procedural document is finalized. **11) The final resolution of this issue will be addressed by NERC as the results-based standard-making procedural document is finalized.** **12) The SDT believes that industry generally supports the exclusion of substations from applicability of the standard, and does not believe that every clause or portion of the Standard needs an explanation in the *Guidelines and Technical Basis*.** **13) The team does not feel that extensive examples, especially of violations, have a place in the Standard.** **14) You have pointed out a conflict in nomenclature between two portions of the standard. The team will resolve the conflict.** **15) As mentioned in both M6 and the VSL table for R6, the TO may choose its unit of measure.** **16) The SDT considered the SAR and FERC Order 693 directives together with the imperative that reliability not suffer with the revised standard, and feels that it has improved the Standard accordingly.**		
20	Kansas City Power & Light	Yes	1. Part R4.3, “Enforcement, under Section 4, “Applicability”, is confusing as to why it is needed. What is the intended purpose of this part? It is clear that each Requirement, Measure, VRF and VSL when adopted by the NERC BOT and FERC become mandatory and enforceable on the declared effective date(s). There is no need for Part R4.3 to reinforce the compliance enforcement dictated by the established NERC Rules of Procedure.2. Requirement R4: The requirement is clear to notify the appropriate control center regarding conditions that might cause a fault on a transmission facility. The requirement should be clear, this for the Transmission Owners applicable lines and recommend the SDT modify the language in R4 to that end. In addition, there is no action other than notification in regards to this operating condition. Highly recommend the SDT consider adding language to take “immediate actions” to remedy the vegetation condition and remove the threat.3. Requirements R5 & R7 are not clear in that they are for the Transmission Owners applicable lines. This has been a common theme throughout this Standard and by the omission of this language, it is not clear that the intended scope of the requirements do not go beyond the applicable lines.
	Response:		

	Organization	Yes or No	Question 8 Comment
	1. Thank you for your comment. NERC staff will address this concern. **2. The SDT feels that the applicability of lines is sufficiently clear in R4. However, it is not appropriate for this Standard to specify any particular action for the TOP to take; this is the realm of TOP-006.** **3. The SDT feels that the applicability of lines is sufficiently clear in R5 and R6.**		
21	American Transmission Company	Yes	1.) Rationale boxes associated with R1, R2 and R3 within the standard include reference Tables and Figures in the “Guidelines and Technical Basis” without specifying where they are located. ATC recommends inserting this information as applicable.2.) ATC raises a previous draft concern on including Rationale Boxes plus Guidelines and Technical Basis as part of the NERC Reliability Standard. ATC recommends that the SDT either remove these sections or make them separate from the formal standard to eliminate any risk that these may be construed as requirements. An alternative method is to very clearly identify which parts of the standard are subject to compliance and considered mandatory and which are not considered requirements and are only for guidance in meeting the requirements. 3.) ATC believes the Measurements are well written and provide guidance on acceptable compliance evidence related to the requirement.4.) Measurement M2 related to R2 states that outages related to encroachments have records confirming no Real-Time observations of any MVCD encroachments. ATC feels this would be hard to prove as a negative. It could require one to show every single patrol or inspection has documentation stating no real time encroachments were observed.5.) Editorial Comment on Draft SDT VSLs for R2: To clarify the statements made for the Moderate, High and Severe VSLs. please add the verbiage, “into the MVCD” after “The TO had an encroachment.......”
	Response: **1) The formatting of these Rationale boxes is not set and will be addressed by NERC as the results-based standard-making procedural document is finalized.** **2) This issue will be addressed by NERC as the results-based standard-making procedural document is finalized.**		

	Organization	Yes or No	Question 8 Comment
	3) Thank you for your comments. **4) As stated in the Measure, an attestation serves as adequate evidence.** **5) Thank you for noticing this oversight. It will be corrected.**		
22	MRO's NERC Standards Review Subcommittee (nsrs)	Yes	1.) The NSRS notices that a previous draft concern on including Rationale Boxes plus Guidelines and Technical Basis as part of the NERC Reliability Standard. The NSRS recommends that the SDT either remove these sections or make them separate from the formal standard to eliminate any risk that these may be construed as requirements. An alternative method is to very clearly identify which parts of the standard are subject to compliance and considered mandatory and which are not considered requirements and are only for guidance in meeting the requirements. Such as; State within in the text that this information "Is not subject to enforcement". 2.) The NSRS believes the Measurements are well written and provide guidance on acceptable compliance evidence related to the requirement.3.) Measurement M2 related to R2 states that outages related to encroachments have records confirming no Real-Time observations of any MVCD encroachments. The NSRS feels this would be hard to prove as a negative. It could require one to show every single patrol or inspection has documentation stating no real time encroachments were observed.4.) Editorial Comment on Draft SDT VSLs for R2: To clarify the statements made for the Moderate, High and Severe VSLs. please add the verbiage, "into the MVCD" after "The TO had an encroachment......."
	Response: **1. This issue will be addressed by NERC as the results-based standard-making procedural document is finalized.** **2. Thank you for your comments.** **3. As stated in the Measure, an attestation serves as adequate evidence.** **4. Thank you for noticing this oversight. It will be corrected.**		

	Organization	Yes or No	Question 8 Comment
23	BGE Forestry Management	Yes	4.2.4 States that the Standard is not applicable to “...to Facilities .... located inside the fenced area of a switchyard, station or substation”. This implies that anything within the fenced area of a switchyard, substation or power plant does not fall within the jurisdiction of FAC-003-2. Some fenced in areas could be very large and susceptible to vegetation encroachments issues. Suggest reference to “inside the fence” be removed.Disagree with R6. - Inspection Frequency. Very prescriptive. Please consider allowing TO’s to select an annual frequency that best fits their requirements, such as calendar year, every growing season, every non-growing season, etc. BGE currently defines their inspection frequency as annually during the non-growing season, October 1 to May 1. BGE believes inspecting during the dormant season is a best practice due to the ability of the inspector to identify vegetation defects, especially off the ROW, which could be hidden during the growing season due to foliage, canopy cover, etc. Also, if a utility elects to leverage an advance technology, such as LiDAR, it provides the most effective results when LiDAR is utilize during the growing season, therefore allowing the results of the advance technology to enhance the fall to spring inspection cycle. Table 1 - Time Horizons, Violation Risk Factors, and Violation Severity Levels The VSL’s for R7 all include “the Transmission Owner failed to complete.....% of its annual work plan (including modifications if any)”. This is not clear to BGE. R7. allows plans to be modified due to changing conditions, for example ROW maintenance could be deferred to the following year due to mutual assistance agreements if the deferment does not violate the encroachment within the MVCD. The VSL implies this is a violation since the “modification” deferred a certain percentage of the planned worked to the following year, therefore 100% of the planned worked wasn’t completed. If the modification was excluded, than 100% of the planned work would have been completed.
	Response: **1. Regarding station boundaries, overall industry consensus is that line-based vegetation programs do not apply inside the station boundary. The SDT believes that “fence” is the best overall term for a station boundary.** **2. While the SDT lauds BGE’s approach, it feels that a calendar year basis affords sufficient flexibility for BGE and other TOs to schedule their inspections.**		

	Organization	Yes or No	Question 8 Comment
	3. The Standard suggests that the TO will begin with an original plan which may then be modified; it is implicit that measurements of plan completion are against the modified plan, not against the original plan.		
24	MidAmerican Energy	Yes	Any references to "observed in real time" should be removed. Vegetation contacts must be verified and references to real time are inappropriate. This causes difficulties in proving a negative in real time.
	Response: The SDT believes that the commenter has misinterpreted the requirement. It is not necessary for the TO to continuously observe; rather, a violation can only be reported if observed in real time.		
25	NERC Staff	Yes	**Effective Dates** • The first item should be re-written to "First calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval is required." • The second item is not needed and should be removed. • The third item is okay but the phrase "where explicit regulatory approval is not required" should be removed. **Exceptions** • Identifying a critical line and then waiting 12 months to perform vegetation management is counter to the risk avoidance strategy that the standard is attempting to accomplish. In effect, this standard permits an entity to identify a major WECC path or an IROL just prior to peak season and then not complete any vegetation management activities until just before the next season 12 months later. This is wholly inappropriate. The Planning Coordinator will identify these lines sufficiently far in advance that the 12-month window will prevent encroachments

	Organization	Yes or No	Question 8 Comment
			• Using the phrase "an element of an IROL" seems confusing because "Element" is a term defined in the glossary. Further, IROL is an identified limit, not a physical component. This should be reworded to say "a facility that is identified to be part of an interface or path impacting an IROL." This is also seen in R1 and R2 and needs to be adjusted there as well. The industry has reviewed this language and has found it to be sufficiently clear. • For newly acquired assets, the 12 month window may be appropriate, but there needs to be a much nearer term inspection undertaken to identify "risky" vegetation. **Definition** • The modified definition assumes the ROW is maintained, which may not be the case (for instance, if a newly acquired asset has not yet been acted upon). An entity could interpret the new definition to indicate that the new owner cannot be performing an initial vegetation inspection if the ROW has not yet been maintained. The phrase "maintained transmission line" should be changed to "applicable transmission line." • The inclusion of the phrase "which may be combined with a general line inspection" is unnecessary and should be removed. In fact, the current definition does not restrict combining the inspection with other field visits, while in the proposed definition that vegetation inspection can only be combined with a general line inspection. **Objectives (Section 3)** • NERC staff is concerned that the purpose states "that could lead to Cascading." This qualifier limits the purpose of the standard, which should be to prevent vegetation-related outages. The more outages there are, the less the overall system reliability; it does not necessarily have to lead to

	Organization	Yes or No	Question 8 Comment
			Cascading to be significant and represent a reasonable risk to the BES. • The term “maintain” might be better than “improve.” **Applicability (Section 4)** • 4.1 Functional Entities • Noticeably absent from the standard is coverage for transmission facilities that connect generators to the interconnected bulk power system. As such, the team should add Generator Owners to the applicability and include such language that was proposed by the ad hoc team: transmission facilities that connect generators to the bulk power system that exceed two spans from the fence-line of the generating plant; coupled with the previous discussion, this provides complete coverage for all transmission facilities and switchyards and substations. This is what is needed to ensure no gaps in vegetation management coverage. • 4.2 Facilities o The identification of critical facilities herein does not recognize the overarching criteria that are being developed in support of the PRC-023 order, and in some respects, in response to Order 693 directives to define the criteria for “critical facilities.” The FAC-003-2 SDT should work in conjunction with the PRC-023 team, which is establishing a set of criteria for identifying critical facilities such that the outcome across all NERC standards is consistent. • “Transmission line” should be capitalized as a NERC-defined term. o 4.2.4: This exclusion seems strange. It would appear that there are no expectations for vegetation management in switchyards, which is unacceptable. We should be able to develop language that requires that a Transmission Owner or Generator Owner maintain vegetation within fenced areas of the

	Organization	Yes or No	Question 8 Comment
			switchyard, station, or substation to the same clearances as one does for the ROWs, without necessarily obligating them to an annual cycle of inspection or management. o **Requirement R4** • "Qualified personnel" should be defined. In the Rationale, some examples are listed, but who else counts as "qualified field personnel"? This was intended to be an incomplete partial list. • "At any moment" is an unnecessary qualifier and should be removed (same for M4). • With respect to the phrase "intentional time delay," intent is a tricky thing to prove. Most standards set clear timelines which kick in regardless of intent, because it diminishes reliability to base a standard on intent. The SDT should consider doing so here. **Requirement R5** • NERC staff is confused by the overall purpose of this requirement. It appears to be a defense to a possible violation for failure to perform some planned vegetation work, but it flips it around and makes it a requirement. A better approach would be to just deal with this in addressing the mitigating/aggravating factors under a violation of R1 and R2. This concept is already part (R1.4) of the existing in-force FERC-approved FAC-003-1, but has been renamed to avoid conflict with terminology in the current NERC compliance guidelines. • The team should be more specific with respect to expectations for "corrective action." There needs to be an expectation that the corrective action needs to maintain an equivalent level of performance consistent with the intent of the vegetation management program. This could include, for example re-

	Organization	Yes or No	Question 8 Comment
			rating lines to reduce max sag until the condition is rectified, enhanced inspection cycles to monitor conditions, etc. It would be useful to define a metric for the success of corrective actions. • The team should be clearer on what constitutes a "constraint." Is it only legal constraints? One interpretation could be resource constraints, which would certainly not be appropriate in this context. The phrase "due to constraints" is also used in the Rationale section. In this context, "constraint" appears to mean congestion on a transmission line. This seems very different from being "constrained from performing planned vegetation work." In fact, the existence of congestion on a line does not necessarily create risk. We would not want entities to make the economic determination that they will put off required vegetation work because it would cost too much in energy sales profits. **Requirement R6** • It would appear necessary to require the use of the inspection information to guide or modify program development as is identified in the Rationale box accompanying the requirement. This is referred to in R7 but is not identified as an expectation from R6. • What are "all applicable transmission lines"? Are those lines covered by both R1 and R2? Clarify this. • "Once per calendar year" requires more guidance. Would two inspections on 12/31/2010 and 1/1/2011 satisfy this requirement? Shouldn't there be a requirement to space these inspections out? Recommend: once per calendar year with no more than 15 months between inspections. • The last sentence of R6's Rationale states that "Transmission Owners should consider local and environmental factors that could warrant more frequent inspection." But the way the

	Organization	Yes or No	Question 8 Comment
			requirement is written, there is no basis for requiring anything more frequent than once per calendar year. If the intent is to have stricter timelines for different registered entities, then the standard would need to be revised. **Compliance** • Additional Compliance Information o Categories of Sustained Outages ▪ Category 3 (Fall-ins from outside the ROW) should be reinstated. Even if it is not required by the standards, Category 3 reporting should be kept. The SDT believes that the current NERC TADS process captures such information adequately. ▪ There is currently a public bulletin to encourage Transmission Owners to report Category 1 and 2 outages within 48 hours. The SDT should consider adding this as a requirement and including it in the new standard as such. The SDT has considered your suggestion and believes that the recognized requirement to promptly self-report any potential violations is sufficient. **VSLs** • The VSL for R3 should be shifted to an approach that simply counts the missing elements: Thanks for your comments. The SDT has modified the VSLs for R3. o lower = missing one element o moderate = missing two elements o high= missing three elements o severe = not having documents • The VSL for R4 uses the phrase “vegetation threat,” which needs to either be conformed to the text of the drafting team or defined. This VSL also uses the phrase “intentional delay” A

	Organization	Yes or No	Question 8 Comment
			truly intentional delay should be labeled as severe, not just high. (And as already stated, intent is a very tricky thing to prove.) In the context of the requirement, Measure and VSL, the term “vegetation threat” is self-evident. Refer to the SDT’s earlier reply regariding “intentional delay”. • For the VSL for R5, there may be ways to differentiate violations based on whether the entity identified appropriate corrective actions (versus missing obvious alternatives), attempted corrective actions but failed, considered alternative corrective action, etc. The SDT has considered this but has not identified a good means of differentiation. Additionally, industry stakeholders have not offered any means of differentiation. The SDT would welcome a proposal. • For the VSL for R6, the SDT should differentiate between the criticality of different lines. At the very least, a failure to inspect R1 lines should be a more severe violation than a failure to inspect R2 lines. The risk to the system is properly addressed by the VRFs, not by the VSLs. • The VSL for R7 should perhaps be differentiated based on whether the incomplete work related to critical versus non-critical or less critical lines (i.e., R1 lines vs. R2 lines). The risk to the system is properly addressed by the VRFs, not by the VSLs. **Guidelines and Technical Basis** • R1/R2 o “If an investigation of a fault by a qualified person confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered a Real-time observation”: This is an important statement and should be included as part of the requirement itself. The SDT feels that this is really more of a “Measure” issue than a “Requirement” issue, and is adequately captured in M1. • R3

	Organization	Yes or No	Question 8 Comment
			o With respect to the phrase "an adequate transmission vegetation management program," the standard talks about factors to consider, but the requirement does not include any provisions on which to base a determination of adequacy. NERC staff believes it should. With NERC's movement to the results-based standard-making techniques, this is an outstanding issue that can best be resolved once RBS techniques are firmly established. o The guideline states, "This approach provides the basis for evaluating the intent, allocation of appropriate resources and the competency of the Transmission Owner in managing vegetation," but nothing in the requirements actually provide explicitly for such evaluations. The SDT asserts that with the totality of R3, M3 and associated VSLs, it is possible for the auditor to assess the TO's intent, competency, etc. • R4 o "Cellular service or two-way radio disabled" should not be considered an acceptable unintentional delay. This seems to be within the entity's control: there may be a difference between whether the cell service problems are due to network problems as opposed to the entity failing to charge the phone or pay the bill. The SDT has considered the comments, but believes the verbiage is adequate. o "Remote field locations" should not be considered an acceptable unintentional delay. This is not entirely beyond the registered entity's control. There may be a difference between a work site that is isolated from radio or cellular networks versus the fact that the employee simply left the radio in the truck. The SDT has considered the comments, but believes the verbiage is adequate. o "Vegetation-related conditions that warrant a response" should be defined in the standard. Qualified personnel

	Organization	Yes or No	Question 8 Comment
			are ab;le to assess the conditions as called for in the Requirement. o It is not clear to NERC staff that a lineman or an arborist is capable of completing “an assessment of the possible sag or movement of the conductor” out in the field in real time. However, if this is the expectation, it should be written into the requirements. The SDT believes it is necessary to rely on field personnel for routine decisions in the field, and that it is impractical and unworkable for engineering or survey teams to examine every questionable site. The SDT has considered the comments, but believes the verbiage is adequate. o The fourth paragraph states that the “Transmission Owner has the responsibility to ensure the proper communication…” Earlier in this section, however, it says that the condition of the communication system is not considered to be intentional delay. This inconsistency needs to be addressed. This sentence should also include a requirement for correcting the vegetation encroachment. The SDT agrees with your observation and will clarify the wording to indicate communication “processes” between field personnel and control centers are the issue being addressed. o The phrase “minutes or hours” is used in the final sentence of the fourth paragraph of this sentence. This detail should be written more clearly and written into the standards. Is 24 hours still hours? What about 48 hours? The SDT has conceived of cases where a 10-hour or more delay may be perfectly acceptable, but others where a 10- or 20-minute delay is inexcusable. The SDT believes that no rigid timeline is appropriate. • R6 o With respect to the following sentence, beginning with “Therefore it is expected,” NERC staff is concerned that

	Organization	Yes or No	Question 8 Comment
			nothing in the requirement actually makes this expectation enforceable. It would be best to require each TO that experiences a vegetation related sustained outage to investigate the outage and make revisions to its TVMP if the investigation shows that the growth rates of vegetation under the TO's control do not match those anticipated in the TVMP. The primary definition of "expected" is "looking forward to a probably occurrence", not a "required activity," and so the SDT believes that the verbiage is appropriate. • R7 o The second paragraph states that "recent line inspections may identify unanticipated high priority work." But the fifth bullet in R7 does not indicate that the higher priority work was identified in a recent line inspection. R7 should be revised to make that caveat clear. The SDT suggests that it is unnecessary to state that the TO will use all information available to it (including inspection results) in identifying unanticipated high-priority work. o The second paragraph references "Modifications to the annual work plan." Presumably, these modifications would not excuse compliance with R1, R2, and R6. That should be made clearer in the requirements. Thank you for the comments. **Table 3** • None of the requirements actually reference this table. That should be modified. Thank you. The Table will be removed. •
	Response:		

	Organization	Yes or No	Question 8 Comment
	Effective Dates **The SDT assumes that NERC staff will correct implementation timetable conflicts.** **Exceptions** **The SDT considered such language, but ultimately determined that it was unnecessary, partly because the response to “hot-spot”-type conditions is not part of this standard.** **Definition** • **Thank you for your excellent comments. The SDT has made changes to meet this concern.** • **Previous overwhelming industry comments have dictated the need for the SDT to clarify this language as it exists in the current draft. The current definition offers no restrictions that the vegetation restriction may only be combined with a general line inspection.** **Objectives (Section 3)** • **The Purpose as currently stated reflects broad industry consensus that earlier Purpose statements were over-reaching.** • **The Purpose as currently stated reflects broad industry consensus.** **Applicability (Section 4)** • **Re: generators - There is a NERC GO/TO team established to address this issue.** • **Re: critical facilities - While the SDT is aware of the interest in FERC to consolidate tests or criteria for so-called “critical” facilities, NERC leadership have indicated to FERC staff its commitment to separate efforts for use by PRC-023 and this standard.** • **Re: capitalizing Transmission Line - The SDT agrees and thanks you for your comments.** • **Re: 4.2.4 - Wide industry consensus is that line-based vegetation programs should not apply inside the station boundary. Also, as previously mentioned, another NERC team is examining the TO/GO issue.** **Requirement R4** • **Re: qualified personnel - The SDT changed the language to confirmation by the Transmission Operator.** • **Re: “At any moment” - The SDT believes that “at any moment” is a necessary but sufficient qualifier.** • **Re: “intentional time delay,” - The SDT has considered this. FERC has already approved other standards with the same language.**		

	Organization	Yes or No	Question 8 Comment
	Requirement R5 • **Re: corrective action - Past and recent industry comments indicate little confusion on this portion of the Standard.** • **Re: constraints - Past and recent industry comments indicate little confusion on this portion of the Standard.** **Requirement R6** • **Re: inspection information - The SDT suggests that it is unnecessary to state that the TO will use all information available to it (including inspection results) in developing its annual plan.** • **Re: "all applicable transmission lines" - Please refer to section 4 ("Applicability") of the draft.** • **Re: calendar year - The SDT posed the question of inspection frequency to the overall industry in an earlier posting and received general consensus that a one-year interval would be appropriate.** • **Re: Rationale - The SDT does not intend that stricter timelines be rigidly defined or employed.** **Compliance** • **Re: Category 3 (Fall-ins from outside the ROW) - The SDT added this back in.** • **Re: Public bulletin - The SDT has considered your suggestion and believes that the recognized requirement to promptly self-report any potential violations is sufficient.** **VSLs** • **Re: VSL for R3 - The SDT has modified the VSLs for R3.** • **Re: VSL for R4 - In the context of the requirement, Measure and VSL, the term "vegetation threat" is self-evident. Refer to the SDT's earlier reply regarding "intentional delay".** • **Re: VSL for R5 - The SDT has considered this but has not identified a good means of differentiation. Additionally, industry stakeholders have not offered any means of differentiation. The SDT would welcome a proposal.** • **Re: VSL for R6 - The risk to the system is properly addressed by the VRFs, not by the VSLs.** • **Re: VSL for R7 - The risk to the system is properly addressed by the VRFs, not by the VSLs.** **Guidelines and Technical Basis** • **Re: R1/R2 - The SDT feels that this is really more of a "Measure" issue than a "Requirement" issue, and is adequately captured in M1.** • **Re: R3 –** o **With NERC's movement to the results-based standard-making techniques, this is an outstanding**		

	Organization	Yes or No	Question 8 Comment
	issue that can best be resolved once RBS techniques are firmly established. o The SDT asserts that with the totality of R3, M3 and associated VSLs, it is possible for the auditor to assess the TO's intent, competency, etc. • Re: R4 - o Re: "Cellular service or two-way radio disabled" - The SDT has considered the comments, but believes the verbiage is adequate. o Re: "Remote field locations" - The SDT has considered the comments, but believes the verbiage is adequate. o Re: "Vegetation-related conditions that warrant a response" - Qualified personnel are able to assess the conditions as called for in the Requirement. o Re: "assessment of the possible sag or movement of the conductor" out in the field - The SDT believes it is necessary to rely on field personnel for routine decisions in the field, and that it is impractical and unworkable for engineering or survey teams to examine every questionable site. The SDT has considered the comments, but believes the verbiage is adequate. o Re: The fourth paragraph - The SDT agrees with your observation and will clarify the wording to indicate communication "processes" between field personnel and control centers are the issue being addressed. o Re: The phrase "minutes or hours" - The SDT has conceived of cases where a 10-hour or more delay may be perfectly acceptable, but others where a 10- or 20-minute delay is inexcusable. The SDT believes that no rigid timeline is appropriate. • Re: R6 - o Re: sentence beginning with "Therefore it is expected," - The primary definition of "expected" is "looking forward to a probable occurrence", not a "required activity," and so the SDT believes that the verbiage is appropriate. • Re: R7 - o Re: The second paragraph - The SDT suggests that it is unnecessary to state that the TO will use all information available to it (including inspection results) in identifying unanticipated high-priority work. o Re: The second paragraph references "Modifications to the annual work plan." - Thank you for the comments. Table 3 • Thank you. Table 3 has been removed.		
26	FirstEnergy	Yes	FE has the following additional comments:1. In the SDT consideration of

	Organization	Yes or No	Question 8 Comment
			comments from Draft 3, it was indicated that "The subcommittee will ask that NERC's legal department write a statement for addition to each standard to clarify which parts/elements of the standard are mandatory and enforceable and which are provided only as information". We would appreciate this statement be placed into the standard before the final ballot so stakeholders have an opportunity to review and comment on the wording.2. We cannot comment on the Technical Reference Document since the latest draft was not posted for review. Does NERC intend to post this at a later time? If so, we ask that NERC give the industry enough time to adequately review the document so that we can provide quality feedback.3. In the Guidelines and Technical Basis Section, in the first paragraph of Requirement R5, second sentence, the word "temporarily" should be removed since it was removed from the requirement.
	Response: **The SDT thanks you for your comments.** **1) The NERC legal department has been contacted to provide a statement to clarify which parts/elements of a standard are mandatory and enforceable and which are provided only as information. This statement is nearing finalization and when completed will be posted as a separate document when the next draft of FAC-003-2 is posted.** **2) The Technical Reference Document is not a mandatory and enforceable document but your feedback is definitely appreciated once the document is finalized. The Technical Reference will be updated during the next ballot which will start during early August. The SDT will finalize the Technical Reference document at the August meeting in Toronto, ON which is scheduled from 8/17-8/19/10 and will post for comment.** **The word 'temporarily' has been removed from the Guidelines and Technical Basis as requested. Thank you for your comment.**		
27	Ameren	Yes	Funding Adjustments (increase or decrease) - need more description to imply only when planned vegetation work is "over and above".
	Response: Thank you for your comment. The SDT believes your observation and question is the same as voiced in Question 5. As stated in the SDT's response to Ameren's Question 5, we reviewed the Funding Adjustment example for R7 and feels this is a valid reason for modifying the Annual Plan keeping in mind that a modification must not place the transmission system at risk of vegetation encroachment into the		

	Organization	Yes or No	Question 8 Comment
	MVCD.		
28	Hydro One	Yes	Hydro One wants to thank the SDT for the effort that has gone into developing this proposed revision to FAC-003. Overall the new version is consistent with FERC Order 693 and will be a straightforward, workable, and auditable standard. One item requiring clarification and change is the Active ROW definition. The recent addition of a centerline distance to edge of Active ROW is not acceptable. In many areas design standards allow a smaller ROW width with no compromise to “cleared width” or tree related reliability of the line. The SDT needs to address this issue. In R5, the phrase 'where a transmission line is put at potential risk due to the constraint' should be better defined. This is vague and could lead to inconsistent practices between utilities. All undesirable species on the full width of the ROW are defined as 'potential risks to the transmission line' regardless of height or location at the time of vegetation management. Interim corrective action should only be required when the potential risk is approaching the imminent threat classification.
	Response: The SDT thanks you for your response. Your objection to our attempt to define a minimum width of the Active Transmission Right of Way was very similar to many other commenters. The SDT has subsequently revised the definition of ROW. **The issue you mention with R5 and “potential risk to the system” is understandable. The SDT changed this.**		
29	Idaho Power Company	Yes	I would like to see something more from NERC to clear the way for utilities to do vegetation management on federal lands that will allow timely vegetation management without delays from these federal entities.
	Response: **Thank you for your comments. This Standard places requirements on the Transmission Owners, not on landowners. There is no legal mechanism for this Standard to take rights from property owners and assign them to the Transmission Owner. There is joint UAA/EEI Task Force that is working on an MOU with the Federal Agencies to address these issues which are outside the purview of NERC Reliability Standards.**		
30	Idaho Power	Yes	I'd like to see language or NERC support to encourage federal agencies to expedite vegetation management maintenance requests and minimize the

	Organization	Yes or No	Question 8 Comment
			barriers to perform work on federal lands.
	Response: **Thank you for your comments. This Standard places requirements on the Transmission Owners, not on landowners. There is no legal mechanism for this Standard to take rights from property owners and assign them to the Transmission Owner. There is joint UAA/EEI Task Force that is working on an MOU with the Federal Agencies to address these issues which are outside the purview of NERC Reliability Standards.**		
31	Dominion	Yes	In R4 and M4, the phrase "without any intentional time delay" has been added. We recommend removing this language from the requirement as it is not possible to measure intent.
	Response: **Thank you for your comment. Please refer to the SDT response to NERC staff above regarding R4.**		
32	Consolidated Edison Company of New York Inc	Yes	In R5, the SDT should better define the phrase 'where a transmission line is put at potential risk due to the constraint.' This is rather vague and could lead to inconsistent practices between utilities. Con Edison defines all undesirable species on the full width of the ROW as 'potential risks to the transmission line' regardless of height or location at the time of vegetation management. Interim corrective action should only be required when the potential risk is approaching the imminent threat classification.
	Response: **The SDT thanks you for your comments. As described in the Technical Reference document (See Page 30), R5 is not intended to address situations where the transmission line is not at potential risk, meaning risk of a Sustained Outage, and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the Transmission Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action. However, in situations where transmission line reliability is potentially at risk due to a constraint, the Transmission Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line.**		

	Organization	Yes or No	Question 8 Comment
33	Orange and Rockland Utilities, Inc.	Yes	In R5, the SDT should better define the phrase 'where a transmission line is put at potential risk due to the constraint.' This is rather vague and could lead to inconsistent practices between utilities. Orange and Rockland Utilities, Inc. defines all undesirable species on the full width of the ROW as 'potential risks to the transmission line' regardless of height or location at the time of vegetation management. Interim corrective action should only be required when the potential risk is approaching the imminent threat classification.
	Response: The SDT thanks you for your comments. As described in the Technical Reference document (See Page 30), R5 is not intended to address situations where the transmission line is not at potential risk, meaning risk of a Sustained Outage, and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the Transmission Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action. However, in situations where transmission line reliability is potentially at risk due to a constraint, the Transmission Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line.		
34	Entergy Services	Yes	ITEMS of concern listed below:ITEM 1: Page 13 of the Standard Draft 4 under Add'l Compliance Information - Periodic Data Submittal......Clarify if Immediate Reporting is expected for outages in Outage Categories 1A, 1B, 2, or 4........or if Quarterly Reporting is all that is expected. It does not specifically say that IMMEDIATE Reporting is Required for any outage type. It is assumed that IMMEDIATE reporting is required for some outages, but is unclear.ITEM 2: Agree that text boxes being used for additional clarity is a benefit if used in a correct and clear manner, but it needs to be specifically stated in the document that the text boxes are to be used for reference only, we will not be required to specifically follow the language in the rationale, and that and each utility should specify their own exact process for addressing each Requirement.ITEM 3: Language should be added to the Guideline and Technical Basis Section to clarify or re-state that this section that this section is for assisting entities in understanding how to comply with the standard but does not contain mandatory actions/activities.ITEM 4: Please clarify defining factors that constitute "wind shear or fresh gale" as referenced in Section 4.4 Other. This is a very unclear interpretation and will most likely be interpreted

	Organization	Yes or No	Question 8 Comment
			differently by all involved if not specified.
	Response: Thank you for your comments. **ITEM 1: There is no requirement in this Standard for immediate reporting of any vegetation outage to the TO's RE. The TO's RE may require more frequent reporting or immediate reporting of any vegetation related outage. There may be other standards that apply to any transmission line outage that require immediate notification to the RE, NERC FERC, FBI, DOT and/or DOE. The SDT has considered your suggestion and believes that the recognized requirement to promptly self-report any potential violations is sufficient.** **ITEM 2: The Rationale boxes are intended to provide clarity and foundation behind each requirement. They are not a part of the requirement and are not sanctionable, as such. You are correct that every TO is required to structure its TVMP to comply with the standard as vegetation conditions exist. The NERC legal department has been contacted to provide a statement to clarify which parts/elements of a standard are mandatory and enforceable and which are provided only as information. This statement is nearing finalization and when completed will be posted as a separate document when the next draft of FAC-003-2 is posted.** **ITEM 3: The Guideline and Technical Reference paper Disclaimer on Page 6 of the document clearly states that the supporting document is supplemental to the reliability standard FAC-003-2 – Transmission Vegetation Management and does not contain mandatory requirements subject to compliance review.** **ITEM 4: Wind Shear and Fresh Gale are defined terms by the National Oceanic Atmospheric Administration (NOAA). Fresh gale is defined as straight line winds of between 39-46 mph. Wind Shear according to NOAA is a complicated formula that no one will ever use. Wind Shear definition according to NOAA Glossary is "The rate at which wind velocity changes from point to point in a given direction (as, vertically). The shear can be speed shear (where speed changes between the two points, but not direction_, direction shear (where direction changes between the two points, but not speed) or a combination of the two.**		
35	Northeast Power Coordinating Council	Yes	NPCC wants to thank the SDT for the effort that has gone into developing this proposed revision to FAC-003. Overall the new version is consistent with FERC Order 693 and will be a straightforward, workable, and auditable standard. One item requiring clarification and change is the Active ROW definition. The recent addition of a centerline distance to edge of Active ROW is not acceptable. In many areas design standards allow a smaller

	Organization	Yes or No	Question 8 Comment
			ROW width with no compromise to "cleared width" or tree related reliability of the line. The SDT needs to address this issue. In R5, the phrase 'where a transmission line is put at potential risk due to the constraint' should be better defined. This is vague and could lead to inconsistent practices between utilities. All undesirable species on the full width of the ROW are defined as 'potential risks to the transmission line' regardless of height or location at the time of vegetation management. Interim corrective action should only be required when the potential risk is approaching the imminent threat classification.
	Response: The SDT thanks you for your response. Your objection to our attempt to define a minimum width of the Active Transmission Right of Way was very similar to many other commenters. The SDT has revised the definition of ROW. **The issue you mention with R5 and "potential risk to the system" is understandable. The SDT amended the language.**		
36	Arizona Public Service Company	Yes	Qualifications needs to be put back in the standard. There needs to be a clearance 1 requirement.
	Response: Thank you for your comments. Training and qualifications are best addressed in the NERC PER standards. Additionally please refer to the SDT response to question 8, comment 42, regarding the issue of Clearance 1.		
37	Xcel Energy	Yes	R1 & R2 states that "types of encroachments include:" - is the way this is worded intended to imply there can be other types of encroachments that are not listed? If not, then rephrase the leading sentence to be definitive and indicate that the types are the only categories to be considered. We suggest that the wording from the prior draft, i.e., " . . . limited to".MCVD should be a defined term in the glossary, not in a "Rationale" box.R1 "1" should Real-time be capitalized to reflect the glossary definition? The term is used as "real time", "Real time" and "Real Time" throughout the standard. This seems to be just a drafting issue, but the same term should be used consistently. Need to establish somewhere that the entity defines what constitutes a "qualified" person. Further, some portions of the standard use the term "qualified person" (e.g., see M1) and others reference "qualified field personnel" (e.g., see the Rational Box near M3). It seems that all references should be to

	Organization	Yes or No	Question 8 Comment
			“qualified field personnel.”R1 & R2 are duplicative. It appears the only reason for the separation is so that different VRFs can be assigned. Why not just have 1 requirement and indicate that the VRF is High for one set of lines and Med for others?In general, the “Rationale” boxes force the requirement language into a difficult to read format.R5/M5 - the measures identified do not constitute “corrective actions”, they merely identify documentation that work was attempted. Corrective actions should be “actions”, such as establish an increased monitoring plan, re-rating of the line, removal from service, etc.R6 - Xcel Energy still believes the requirement in R6 that mandates an annual inspection is too onerous and is at odds with the results-based approach of these revisions. Xcel Energy urges the retention of the provision in the existing standard that allows the Transmission Owner to set the frequency of inspection. In some areas of the country, annual inspections may not be adequate. Yet in other areas, a longer inspection frequency may be perfectly reasonable and practical. Our point is that inspection frequency should not be treated as if it were “one size fits all”. If treated this way, we feel this could pose a risk to reliability and is not likely to be cost-effective. The Transmission Owner should be allowed some flexibility. However, if the drafting team disagrees and determines that an annual inspection is to be mandated, Xcel Energy believes that an exception to the annual inspection is appropriate when a non-subjective advanced technology such as LIDAR is utilized to achieve actual clearance distances. This places the Transmission Owner in a situation where it can rationally determine that the objectively measured distances result in a situation where an inspection need not be performed within the next year. It is suggested that R6 be revised to read as follows: Each Transmission Owner shall perform a Vegetation Inspection of all applicable transmission lines at least once per calendar year, unless the Transmission Owner, based on a non-subjective advanced technology, such as LIDAR, determines that a longer inspection period is appropriate.The Effective Dates section is confusing - exactly when would this standard be in effect? It lists 3 approvals...do all three have to be met or just one?The reference to Major WECC transfer paths in the requirements introduces a weak element. The WECC major path designation and elements that comprise those paths should be controlled through a robust process and easily available to WECC members. Currently, there are some concerns around that process in general.NERC’s concerns regarding reporting vegetation related outages within 48 hours

	Organization	Yes or No	Question 8 Comment
			should be addressed or clarified in the Compliance section. (i.e., incorporate or indicate that this supersedes that recommendation). Ref: Public Notice - NERC Compliance Process #2008 - 001
	Response: Thank you for your comments. The yellow highlighting refers to commenter issues. The SDT response follows. **R1 & R2 states that "types of encroachments include:": To address your concern, there are only (4) types of failure- to- manage types of encroachment as defined in R1 and R2 as it relates to compliance with FAC-003-2. The SDT appreciates your perspective but believes the requirement as written is clear to the point of only four encroachment types.** **MCVD should be a defined term in the glossary, not in a "Rationale": This term refers to a Table of values that is clearly defined within the standard itself.** **The term is used as "real time", "Real time" and "Real Time" throughout the standard. : Thanks for identifying this inconsistency and the SDT will review and address as appropriate.** **Need to establish somewhere that the entity defines what constitutes a "qualified" person.: This was replaced with confirmed by the Transmission Owner.** **Further, some portions of the standard use the term "qualified person" (e.g., see M1) and others reference "qualified field personnel" (e.g., see the Rational Box near M3).: Thanks for recognizing this inconsistency. The term "qualified" was replaced with confirmed by the Transmission Owner.** **R1 & R2 are duplicative. It appears the only reason for the separation is so that different VRFs can be assigned. Why not just have 1 requirement and indicate that the VRF is High for one set of lines and Med for others?: The SDT is following the VSL and VRF Guidelines which required us to designate two requirements since the VRFs are different for the applicable lines in the two requirements.** **R5/M5 - the measures identified do not constitute "corrective actions", they merely identify documentation that work was attempted.: The measures in R5 are evidence that appropriate corrective action was taken by the TO. Trying to identify very specific actions would be prescriptive in nature and difficult to cover a broad spectrum of potential corrective actions.** **R6 that mandates an annual inspection is too onerous and is at odds with the results-based approach of these revisions: As stated in previous comment responses, the SDT was directed by Order 693 to set a minimum inspection criteria and the SDT feels that an annual inspection is a reasonable minimum frequency.** **Effective Dates section is confusing - exactly when would this standard be in effect? The SDT has revised the effective date language for clarity. Please refer to change in revised draft.**		

	Organization	Yes or No	Question 8 Comment
	WECC major path designation and elements that comprise those paths should be controlled through a robust process and easily available to WECC members. Currently, there are some concerns around that process in general. : This is an issue that needs to be directed to WECC rather than the SDT. **48 hours should be addressed or clarified in the Compliance section. (i.e., incorporate or indicate that this supersedes that recommendation). Ref: Public Notice - NERC Compliance Process #2008 – 001: This Public Notice is a requirement for a Regional Entity to report to NERC.**		
38	BC Hydro	Yes	1. R4 - There will likely be issues of definition over what constitutes an “intentional delay” in notification. The time for reasonable reporting needs to be quantified. 2. The standard references Tables 2 and 3 but there is no Table 1 in the document. This is confusing and should be renumbered. This is likely a carry over from an earlier draft where a Table 1 has been renamed or dropped. 3. As noted earlier in Q1, table 3 is poorly developed and should be revisited.C 4. How does one objectively measure compliance to MVCD distances? Use of LiDAR technology, laser rangefinders, etc. should be used and evidence of potential violations should be empirical and not based solely on subjective observations, even if they are performed by “qualified personnel”. 5. The technical document should include a glossary of all the acronyms used throughout the document as it has some excessive jargon and does not always read smoothly, especially compared to FAC-003- The use of explanation boxes is helpful.
	Response: **1 The SDT debated a set time limit. The team could not find a time that would fit all situations. Intentional would apply if a TO withheld notification after having confirmed that risk conditions exist.** **2 The standard has been revised** **3 The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of ROW.**		

	Organization	Yes or No	Question 8 Comment
	4 The determination of a potential violation should employ any technology available 5 SDT has defined unusual terms not found within the industry. 6 Thank you		
39	The United Illuminating Company	Yes	R4:In R4 the phrase: without any intentional time delay, is a concern. There is a time line between identification and reporting of an imminent hazard that represents the minimal time required to complete this Requirement. Any situation where the time between observation and reporting is greater than this minimal time line indicates a time delay occurred. It will be left to the compliance enforcement authority to determine if this delay was intentional or not. It is not proper for the test to be based on Intentional versus Non-Intentional. Using other synonyms such as reasonable, expeditious, prompt, immediate or without hesitation all introduce a qualitative not a quantitative attribute to the measurement. The Supplemental Reference for R4 indicates that the imminent threat requirement is measured in minutes or hours; again no guidance for enforcement. R4 would be improved with an explicit time requirement of 6 hours between observation and report. This is measurable and clear.R4 should be: Each Transmission Owner shall notify the control center holding switching authority for the associated transmission line no more than 6 hours of a qualified personnel confirm the existence of a vegetation condition that is likely to cause a Fault at any moment.Other commenter's will argue that 6 hours is arbitrary or unduly prescriptive. I believe it is in line with the Supplemental Reference and adds clarity to the enforcement process.M4 becomes Each Transmission Owner that has a vegetation condition likely to cause a Fault at any moment, as confirmed by qualified personnel, will have evidence that it notified the control center holding switching authority for the associated transmission line within 6 hours of observation.The Transmission Owner can use the inspection as evidence of the time of observation.Effective Dates: The effective dates in the implementation Plan is in a different form then UI was expecting. Effective Date 1 UI has no comment.Effective date number 2 implies that if the BOT approves the standard and FERC takes no action (neither approves, remands or withholds approval of the standard) then the standard will become effective in one year. This seems to create the possibility of an effective standard without enforceability.Effective Date number 3 implies that regardless of any action by FERC the standard will become effective at least

	Organization	Yes or No	Question 8 Comment
			one year following BOT approval. Again this creates an effective standard without enforceability. Also the use of "at least one year" does not add any clarity to when the Standard would be effective any way.
	Response: **Thank you for your comments. The SDT considered a fixed time as you offer. We rejected that alternative as the situations under which conditions are found that can cause a Fault at any moment vary widely based on the terrain, weather and available transportation and communication methods. This Requirement is directing the TO to communicate the condition as soon as the above mentioned constraints will allow.** **We have addressed your concerns by revising the effective date language.**		
40	FPL Corporate Compliance	Yes	R5 as written is vague. It leads to confusion in interpretation. FPL recommends the following wording.R5. The Transmission Owner shall certify each corridor or line section that it meets the standards it set forth under R3 until the next planned management cycle when it is completed. If a location in known to not meet the criteria defined under R3, a mitigation plan must be in place to prevent a violation of R1 or R2.R1 and R2 are too inclusive. They equate vegetation growing in to conductors from below the same as vegetation falling or blowing into the conductors from within the Active ROW. There is no evidence that a cascading event has ever been caused by the latter two events. This standard should concentrate on vegetation growing from below the conductor. Suggested wording of R1 and R2 is as follows.R1. Each Transmission Owner shall manage vegetation to prevent encroachment into the Minimum Vegetation Clearance Distance (MVCD) as shown in Table 2 from within the active ROW on of any line identified as an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions). Encroachments are determined by: 1. An encroachment, observed in real time, 4. An encroachment due to a grow-in from below the conductor in the active ROW that caused a Fault.R1. Each Transmission Owner shall manage vegetation to prevent encroachment into the Minimum Vegetation Clearance Distance (MVCD) as shown in Table 2 from within the active ROW on of any line that is not an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions). Encroachments are determined by:

	Organization	Yes or No	Question 8 Comment
			1. An encroachment, observed in real time, 4. An encroachment due to a grow-in from below the conductor in the active ROW that caused a Fault.
	Response: The STD recognizes that defining any risk is subjective. Removing the term does not change the fact that each TO must determine the risk and respond accordingly. **The SDT has placed reference to the different severity of the respective violations into R1 and R2. Both NERC and FERC are on record that fall-in and blow-in interruptions place sufficient risk to the system that they should be part of the standard.**		
41	MWDSC (METROPOLITAN WATER DISTRICT OF SOUTHERN CALIFORNIA)	Yes	Requirement R4.uses the phrase "notify the control center holding switching authority for the associated transmission line" when a vegetation condition is confirmed which is likely to cause a Fault. Switching jurisdiction may be assigned to a manned substation located closer to a line rather than a remote 24/7 manned control center. However, the switching substation will notify its control center. The control center may need to notify and coordinate with its Balancing Authority or neighboring control centers. Suggest changing the phrase as follows: "notify the appropriate control center(s)for the associated transmission line"
	Response: The SDT thanks you for your comments. The example you provided in your comment is in compliance with the Requirement as written. The local procedure developed by a Transmission Owner may involve multiple notification steps but, as long as the proper operating personnel holding switching authority for that associated line is notified without any intentional delay, the Requirement is met. Due to multiple variations in utility notification procedures across North America, the SDT has decided to retain the existing language in the current draft.		
42	Southern California Edison Company	Yes	SCE questions the need for including the “Guidelines and Technical Basis” section within the body of the standard and is also curious as to the criteria used in developing new Table 3.SCE finds this Draft (4) to be the best work product thus far, and commends the SDT for its efforts and continued dedication to crafting a best-in-class standard.
	Response: The SDT thanks you for your comment. The ‘Guidelines and Technical Basis” is part of the format change with a “results based” standard. The idea is to bring some of the technical reference documentation into the Standard. This will hopefully make the entire Standard a more complete document and will reduce the need to have both the Standard and the Technical Reference Document in hand.		

	Organization	Yes or No	Question 8 Comment
	Table 3 was an attempt to define a "minimum width" of the Active Transmission Right of Way. This table, along with the footnote, has been removed from the Standard. The definition of Right of Way has been changed in the Glossary.		
43	Bonneville Power Administration	Yes	The basis of managing vegetation to MVCD in Table 2 (essentially withstand distances) will likely prove problematic. BPA believes NERC should develop an additional table that calls out minimum "buffers" based on attributes such as line voltage, line rating etc. This table should be a companion to Table 2. It is NERC's responsibility to regulate and we believe that they should do so. In this case, the loss of flexibility for the owners is not necessarily a bad thing.
	Response: The SDT thanks you for your comments. As described in the Background Section of the Standard, FAC-003-2 is being drafted utilizing a Results Based Standard approach. One component of this type of Standard is that requirements within a standard are not too prescriptive allowing for flexibility. An additional Table would be considered overly prescriptive and in direct conflict with our guidance. It is the Transmission Owner's responsibility to identify the 'buffers' that you mention, not NERC. Since conditions vary significantly across North America, maintaining this specific buffer distance may not be feasible for all utilities.		
44	Southern Company Transmission	Yes	The NERC Glossary of Terms provides a definition for Flashover. The Rationale boxes for R1 and R2 use the term "spark-over". This is inconsistent with other references in the Standard. Note that the term Flashover is used in footnote No.4. Please resolve the inconsistency between these terms.We are concerned FAC-003-2 is being developed under a zero tolerance philosophy, while other NERC standards do not adopt a zero tolerance philosophy. Industry performance under FAC-003-1 indicates the standard is working and that industry is responding to ensure reliability of the electric Transmission system.We would like to thank the SDT for the work they have put into developing the proposed draft.
	Response: **The SDT thanks you for your response. The technically correct term for the electric discharge through air is "spark-over". In the Technical Reference Document this term is used. The technical definition of "flash-over" refers to the electric discharge over the surface of insulation when the "withstand" of the air is less than the "withstand" of the insulation and the insulator "flashes over".**		

	Organization	Yes or No	Question 8 Comment
	However, the commonly used term in industry for both phenomena is "flash over". The NERC Glossary definition has actually rolled the technical definition of both terms together into one definition. **The SDT has decided to use the term "flash-over" in all sections of the Standard except for the derivation of the Gallet equations in the appendix of the Technical Reference Document. Hopefully this will alleviate any confusion.** **The SDT recognizes that the current version of the Standard is zero tolerance and believes it is compelled to write the new version it that way. FERC staff and NERC assert that a revised standard cannot result in less reliability than the one it replaces, and, their belief is the current Standard is zero tolerance.**		
45	ITC Transmission	Yes	We were beginning to except Version 3 to the standard but with the addition of "Table 3, Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW" is totally unacceptable. This entire reference should be stricken from the standard. ITC can not support this table #3 and Version 4 is unacceptable.
	Response: The SDT thanks you for your comments. Based on your comment and others, the SDT has revised the definition of ROW in the NERC Glossary.		

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SC approved SAR for initial posting (January 11, 2007).
2. SAR posted for comment (January 15–February 14, 2007).
3. SAR posted for comment (April 10–May 9, 2007).
4. SC authorized moving the SAR forward to standard development (June 27, 2007).
5. First draft of proposed standard posted (October 27, 2008-November 25, 2008)).
6. Second draft of revised standard posted (September 10, 20-October 24, 2009).
7. Third draft of revised standard posted (March 1, 2010-March 31, 2010).
8. Forth draft of revised standard posted (June 17, 2010-July 17, 2010).

Proposed Action Plan and Description of Current Draft

This is the third posting of the proposed revisions to the standard in accordance with Results-Based Criteria and the fifth draft overall.

Future Development Plan

Anticipated Actions	Anticipated Date
Recirculation ballot of standards.	January 2011
Receive BOT approval	February 2011

Effective Dates

First calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval is required.

Exceptions:

A line operated below 200kV, designated by the Planning Coordinator as an element of an IROL or as a Major WECC transfer path, becomes subject to this standard 12 months after the date the Planning Coordinator or WECC initially designates the line as being subject to this standard.

An existing transmission line operated at 200kV or higher that is newly acquired by an asset owner and was not previously subject to this standard, becomes subject to this standard 12 months after the acquisition date of the line.

Version History

Version	Date	Action	Change Tracking
1	TBA	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	01/20/06
1	April 4, 2007	Regulatory Approval — Effective Date	New
2			

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary. When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.

Right-of-Way (ROW)

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.

> The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

Vegetation Inspection

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

> The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.
>
> Current definition of Vegetation Inspection: The systematic examination of a transmission corridor to document vegetation conditions.

Introduction

1. **Title:** Transmission Vegetation Management

2. **Number:** FAC-003-2

3. **Objectives:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

4. **Applicability**

4.1. Functional Entities:

Transmission Owners

4.2. Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities:

4.2.1. Overhead transmission lines operated at 200kV or higher.

4.2.2. Overhead transmission lines operated below 200kV having been identified as included in the definition of an Interconnection Reliability Operating Limit (IROL) under NERC Standard FAC-014 by the Planning Coordinator.

4.2.3. Overhead transmission lines operated below 200 kV having been identified as included in the definition of one of the *Major WECC Transfer Paths in the Bulk Electric System*.

4.2.4. This standard applies to overhead transmission lines identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

4.3. Enforcement: *The reliability obligations of the applicable entities and facilities are*

Rationale

-The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) The standard was written for Transmission Owners. Rolling the excluded areas into this standard will bring GO and DP into the standard, even though NERC has an initiative in place to address this bigger registry issue. 4) Specifically addressing the areas where the standard applies or doesn't makes the standard stronger as it relates to clarity.

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies"*.

contained within the technical requirements of this standard. [Straw proposal]

5. Background:

This NERC Vegetation Management Standard ("Standard") uses a defense-in-depth approach to improve the reliability of the electric Transmission System by preventing those vegetation related outages that could lead to Cascading. This Standard is not intended to address non-preventable outages such as those due to vegetation fall-ins or blow-ins from outside the Right-of-Way, vandalism, human activities and acts of nature. Operating experience indicates that trees that have grown out of specification have contributed to Cascading, especially under heavy electrical loading conditions.

With a defense-in-depth strategy, this Standard utilizes three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

a) Performance-based — defines a particular reliability objective or outcome to be achieved.

b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels.

c) Competency-based — defines a minimum capability an entity needs to have to demonstrate it is able to perform its designated reliability functions.

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard. For this Standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

Thus the various requirements associated with a successful vegetation program could be viewed as using R1, R2 and R3 as first levels of defense; while R4 could be a subsequent or final level of defense. R6 depending on the particular vegetation approach may be either an initial defense barrier or a final defense barrier.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the Standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the Standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.

This Standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This Standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this Standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of multiple line failures and Cascading. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are statistically intermittent. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this Standard’s emphasis is on vegetation grow-ins.

Requirements and Measures

R1. Each Transmission Owner shall manage vegetation to prevent encroachments of the types shown below, into the Minimum Vegetation Clearance Distance (MVCD) of any of its applicable line(s) identified as an element of an Interconnection Reliability Operating Limit (IROL) in the planning horizon by the Planning Coordinator; or Major Western Electricity Coordinating Council (WECC) transfer path(s); operating within its Rating and all Rated Electrical Operating Conditions.[2]

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,
2. An encroachment due to a fall-in from inside the Right-of-Way (ROW) that caused a vegetation-related Sustained Outage,
3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,
4. An encroachment due to a grow-in that caused a vegetation-related Sustained Outage.

[VRF – High] [Time Horizon – Real-time]

Rationale
The MVCD is a calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method. The types of failure to manage vegetation are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO's vegetation maintenance program since the encroachments listed require different and increasing levels of skills and knowledge and thus constitute a logical progression of how well, or poorly, a TO manages vegetation relative to this Requirement.

M1. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments.

If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. (R1)

[2] This requirement does not apply to circumstances that are beyond the control of a Transmission Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

R2. Each Transmission Owner shall manage vegetation to prevent encroachments of the types shown below, into the MVCD of any of its applicable line(s) that is not an element of an IROL; or Major WECC transfer path; operating within its Rating and all Rated Electrical Operating Conditions.[2]

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,
3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,
4. An encroachment due to a grow-in that caused a vegetation-related Sustained Outage.

[VRF – Medium] [Time Horizon – Real-time]

Rationale

The MVCD is a calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method. The types of failure to manage vegetation are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO's vegetation maintenance program since the encroachments listed require different and increasing levels of skills and knowledge and thus constitute a logical progression of how well, or poorly, a TO manages vegetation relative to this Requirement.

M2. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments.

If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. (R2)

R3. Each Transmission Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable transmission lines that include(s) the following:

3.1 Accounts for the movement of applicable transmission line conductors under their Facility Rating and all Rated Electrical Operating Conditions;

3.2 Accounts for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

Rationale

The documentation provides a basis for evaluating the competency of the Transmission Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the Transmission Owner avoids vegetation-to-wire conflicts under all Rated Electrical Operating Conditions. See Figure 1 for an illustration of possible conductor locations.

[VRF – Lower] [Time Horizon – Long Term Planning]

M3. The maintenance strategies or procedures or processes or specifications provided demonstrate that the Transmission Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

R4. Each Transmission Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable transmission line when the Transmission Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment.

Rationale

To ensure expeditious communication between the Transmission Owner and the control center when a critical situation is confirmed.

[VRF – Medium] [Time Horizon – Real-time]

M4. Each Transmission Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When a Transmission Owner is constrained from performing vegetation work, and the constraint may lead to a vegetation encroachment into the MVCD of its applicable transmission lines prior to the implementation of the next annual work plan then the Transmission Owner shall take corrective action to ensure continued vegetation management to prevent encroachments.

[VRF – Medium] [Time Horizon – Operations Planning]

Rationale

Legal actions and other events may occur which result in constraints that prevent the Transmission Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the Transmission Owner to put interim measures in place, rather than do nothing.

The corrective action process is intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

M5. Each Transmission Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, and evidence that a line was de-energized. (R5)

R6. Each Transmission Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 months between inspections on the same ROW.[3]

[VRF – Medium] [Time Horizon – Operations Planning]

M6. Each Transmission Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable transmission lines at least once per calendar year but with no more than 18 months between inspections on the same ROW. Examples of acceptable

Rationale

Inspections are used by Transmission Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

[3] When the Transmission Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO is granted a time extension that is equivalent to the duration of the time the TO was prevented from performing the Vegetation Inspection.

forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each Transmission Owner shall complete 100% of its annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not put the transmission system at risk of a vegetation encroachment) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include:

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of a Transmission Owner[4]
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

[VRF – Medium] [Time Horizon – Operations Planning]

Rationale

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. An annual vegetation work plan allows for work to be modified for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that the changes do not violate the encroachment within the MVCD.

M7. Each Transmission Owner has evidence that it completed its annual vegetation work plan. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (including modifications if any), dated work orders, dated invoices, or dated inspection records. (R7)

[4] Circumstances that are beyond the control of a Transmission Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, major storms as defined either by the TO or an applicable regulatory body, ice storms, and floods; arboricultural, horticultural or agricultural activities.

Compliance

Compliance Enforcement Authority

- Regional Entity

Compliance Monitoring and Enforcement Processes:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints
- Periodic Data Submittals

Evidence Retention

The Transmission Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

Additional Compliance Information

Periodic Data Submittal: The Transmission Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable transmission lines determined by the Transmission Owner to have been caused by vegetation, except as excluded in footnote 2, which includes as a minimum, the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable transmission lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;

- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable transmission lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable transmission lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable transmission lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable transmission lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable transmission lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable transmission lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by Transmission Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Time Horizons, Violation Risk Factors, and Violation Severity Levels

Table 1

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High	The Transmission Owner had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.	The Transmission Owner had an encroachment into the MVCD due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner had an encroachment into the MVCD due to a grow-in that caused a vegetation-related Sustained Outage.
R2	Real-time	Medium	The Transmission Owner had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.	The Transmission Owner had an encroachment into the MVCD due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner had an encroachment into the MVCD due to a grow-in that caused a vegetation-related Sustained Outage.
R3	Long-Term Planning	Lower		The Transmission Owner has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between	The Transmission Owner has maintenance strategies or documented procedures or processes or specifications but has not accounted for the	The Transmission Owner does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the

				vegetation growth rates, vegetation control methods, and inspection frequency, for the Transmission Owner's applicable lines.	movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the Transmission Owner's applicable lines.	encroachment of vegetation into the MVCD, for the Transmission Owner's applicable lines.
R4	Real-time	Medium			The Transmission Owner experienced a confirmed vegetation threat and notified the control center holding switching authority for that transmission line, but there was intentional delay in that notification.	The Transmission Owner experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that transmission line.
R5	Operations Planning	Medium				The Transmission Owner did not take corrective action when it was constrained from performing planned vegetation work where a transmission line was put at potential risk.
R6	Operations Planning	Medium	The Transmission Owner failed to inspect 5% or less of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or	The Transmission Owner failed to inspect more than 5% up to and including 10% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The Transmission Owner failed to inspect more than 10% up to and including 15% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The Transmission Owner failed to inspect more than 15% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).

			kilometers, etc.)			
R7	Operations Planning	Medium	The Transmission Owner failed to complete up to 5% of its annual vegetation work plan (including modifications if any).	The Transmission Owner failed to complete more than 5% and up to 10% of its annual vegetation work plan (including modifications if any).	The Transmission Owner failed to complete more than 10% and up to 15% of its annual vegetation work plan (including modifications if any).	The Transmission Owner failed to complete more than 15% of its annual vegetation work plan (including modifications if any).

Variances

None.

Interpretations

None.

Guideline and Technical Basis

Requirements R1 and R2:
R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the prevention of vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each Transmission Owner to manage vegetation to prevent encroachment within the Minimum Vegetation Clearance Distance ("MVCD") of transmission lines. R1 is applicable to lines "identified as an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions) to avoid a Sustained Outage". R2 applies to all other applicable lines that are not an element of an IROL or Major WECC Transfer Path.

The separation of applicability (between R1 and R2) recognizes that an encroachment into the MVCD of an IROL or Major WECC Transfer Path transmission line is a greater risk to the electric transmission system. Applicable lines that are not an element of an IROL or Major WECC Transfer Path are required to be clear of vegetation but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

These requirements (R1 and R2) state that if vegetation encroaches within the distances in Table 1 in Appendix 1 of this supplemental Transmission Vegetation Management Standard FAC-003-2 Technical Reference document, it is in violation of the standard. Table 2 tabulates the distances necessary to prevent spark-over based on the Gallet equations as described more fully in Appendix 1 below.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating (potentially in violation of other standards), the occurrence of a clearance encroachment may occur. For example, emergency actions taken by a Transmission Operator or Reliability Coordinator to protect an Interconnection may cause the transmission line to sag more and come closer to vegetation, potentially causing an outage. Such vegetation-related outages are not a violation of these requirements.

Evidence of violation of Requirement R1 and R2 include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to blowing together of applicable lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. If an investigation of a Fault by a Transmission Owner confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered the equivalent of a Real-time observation.

With this approach, the VSLs were defined such that they directly correlate to the severity of a failure of a Transmission Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the goal of "preventing a Sustained Outage that could lead to Cascading." Thus violation severity increases with a Transmission Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example, a limb may only partially break and intermittently contact a conductor. Such events are considered to be a single vegetation-related Sustained Outage under the Standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

Requirement R3:
Requirement R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, a Transmission Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the Transmission Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the Transmission System. The approach provides the basis for evaluating the intent, allocation of appropriate resources and the competency of the Transmission Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the Transmission Owner must be able to state what its approach is and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach a Transmission Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the Transmission Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor’s position in space at any point in time is continuously changing as a reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below.

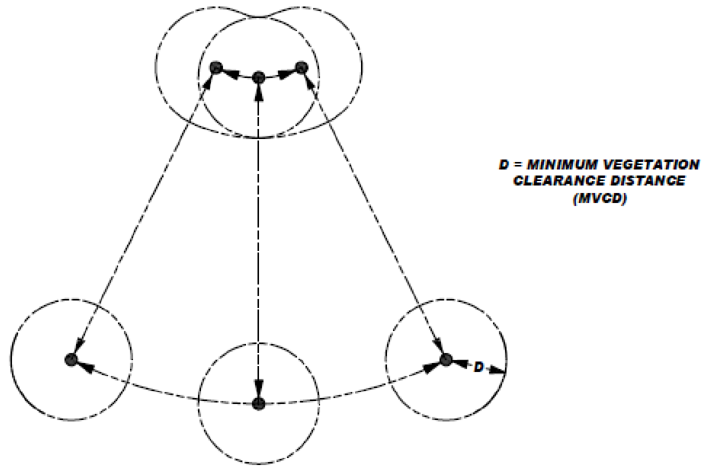

Figure 1

Cross-section view of a single conductor at a given point along the span showing six possible conductor positions due to movement resulting from thermal and mechanical loading.

Requirement R4:

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the Transmission Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of a Transmission Owner's employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The Transmission Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or positioning the system in recognition of the increasing risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some Transmission Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5:
R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the Transmission Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the Transmission Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the Transmission Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the Transmission Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the Transmission Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the Transmission Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for each location.
- In developing the specific action to mitigate the potential risk to the transmission line the Transmission Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The Transmission Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:
R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections that fits general industry practice. In addition, the fact that Vegetation Inspections can be performed in conjunction with general line inspections further facilitates a Transmission Owner's ability to meet this requirement. However, the Transmission Owner may determine that more frequent inspections are needed to maintain reliability levels, dependent upon such factors as anticipated growth rates of the local vegetation, length of the growing season for the geographical area, limited ROW width, and rainfall amounts. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSL for Requirement R6 has VSL categories ranked by the percentage of the required ROW inspections completed. To calculate the percentage of inspection completion, the Transmission Owner may choose units such as: line miles or kilometers, circuit miles or kilometers, pole line miles, ROW miles, etc.

For example, when a Transmission Owner operates 2,000 miles of 230 kV transmission lines this Transmission Owner will be responsible for inspecting all 2,000 miles of 230 kV transmission lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

Requirement R7:
R7 is a risk-based requirement. The Transmission Owner is required to implement an annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a "span-by-span", or even a "line-by-line" detailed description of all work to be performed. It is only intended to require that the Transmission Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

The ability to modify the work plan allows the Transmission Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the Transmission Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan. Modifications to the annual work plan must always ensure the reliability of the electric Transmission system.

In general, the vegetation management maintenance approach should use the full extent of the Transmission Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management in the long term because it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the Transmission Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Transmission Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the Transmission Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[5]

For **Alternating Current** Voltages

(AC) Nominal System Voltage (kV)	(AC) Maximum System Voltage (kV)	MVCD feet (meters) sea level	MVCD feet (meters) 3,000ft (914.4m)	MVCD feet (meters) 4,000ft (1219.2m)	MVCD feet (meters) 5,000ft (1524m)	MVCD feet (meters) 6,000ft (1828.8m)	MVCD feet (meters) 7,000ft (2133.6m)	MVCD feet (meters) 8,000ft (2438.4m)	MVCD feet (meters) 9,000ft (2743.2m)	MVCD feet (meters) 10,000ft (3048m)	MVCD feet (meters) 11,000ft (3352.8m)
765	800	8.06ft (2.46m)	8.89ft (2.71m)	9.17ft (2.80m)	9.45ft (2.88m)	9.73ft (2.97m)	10.01ft (3.05m)	10.29ft (3.14m)	10.57ft (3.22m)	10.85ft (3.31m)	11.13ft (3.39m)
500	550	5.06ft (1.54m)	5.66ft (1.73m)	5.86ft (1.79m)	6.07ft (1.85m)	6.28ft (1.91m)	6.49ft (1.98m)	6.7ft (2.04m)	6.92ft (2.11m)	7.13ft (2.17m)	7.35ft (2.24m)
345	362	3.12ft (0.95m)	3.53ft (1.08m)	3.67ft (1.12m)	3.82ft (1.16m)	3.97ft (1.21m)	4.12ft (1.26m)	4.27ft (1.30m)	4.43ft (1.35m)	4.58ft (1.40m)	4.74ft (1.44m)
230	242	2.97ft (0.91m)	3.36ft (1.02m)	3.49ft (1.06m)	3.63ft (1.11m)	3.78ft (1.15m)	3.92ft (1.19m)	4.07ft (1.24m)	4.22ft (1.29m)	4.37ft (1.33m)	4.53ft (1.38m)
161*	169	2ft (0.61m)	2.28ft (0.69m)	2.38ft (0.73m)	2.48ft (0.76m)	2.58ft (0.79m)	2.69ft (0.82m)	2.8ft (0.85m)	2.91ft (0.89m)	3.03ft (0.92m)	3.14ft (0.96m)
138*	145	1.7ft (0.52m)	1.94ft (0.59m)	2.03ft (0.62m)	2.12ft (0.65m)	2.21ft (0.67m)	2.3ft (0.70m)	2.4ft (0.73m)	2.49ft (0.76m)	2.59ft (0.79m)	2.7ft (0.82m)
115*	121	1.41ft (0.43m)	1.61ft (0.49m)	1.68ft (0.51m)	1.75ft (0.53m)	1.83ft (0.56m)	1.91ft (0.58m)	1.99ft (0.61m)	2.07ft (0.63m)	2.16ft (0.66m)	2.25ft (0.69m)
88*	100	1.15ft (0.35m)	1.32ft (0.40m)	1.38ft (0.42m)	1.44ft (0.44m)	1.5ft (0.46m)	1.57ft (0.48m)	1.64ft (0.50m)	1.71ft (0.52m)	1.78ft (0.54m)	1.86ft (0.57m)
69*	72	0.82ft (0.25m)	0.94ft (0.29m)	0.99ft (0.30m)	1.03ft (0.31m)	1.08ft (0.33m)	1.13ft (0.34m)	1.18ft (0.36m)	1.23ft (0.37m)	1.28ft (0.39m)	1.34ft (0.41m)

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above).

[5] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

Table 2 (cont.) — Minimum Vegetation Clearance Distances (MVCD)
For **Direct Current** Voltages

(DC) Nominal Pole to Ground Voltage (kV)	MVCD feet (meters) sea level	MVCD feet (meters) 3,000ft (914.4m) Alt.	MVCD feet (meters) 4,000ft (1219.2m) Alt.	MVCD feet (meters) 5,000ft (1524m) Alt.	MVCD feet (meters) 6,000ft (1828.8m) Alt.	MVCD feet (meters) 7,000ft (2133.6m) Alt.	MVCD feet (meters) (8,000ft (2438.4m) Alt.	MVCD feet (meters) 9,000ft (2743.2m) Alt.	MVCD feet (meters) 10,000ft (3048m) Alt.	MVCD feet (meters) 11,000ft (3352.8m) Alt.
±750	13.92ft (4.24m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.9ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.07ft (3.07m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	(13.54ft 4.13m)
±500	7.89ft (2.40m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	4.78ft (1.46m)	5.35ft (1.63m)	5.55ft (1.69m)	5.75ft (1.75m)	5.95ft (1.81m)	6.15ft (1.87m)	6.36ft (1.94m)	6.57ft (2.00m)	6.77ft (2.06m)	6.98ft (2.13m)
±250	3.43ft (1.05m)	4.02ft (1.23m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5ft (1.52m)	5.17ft (1.58m)

<u>Notes:</u>

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 5 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 7 would have to be used. Table 7 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 242 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America [1].

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations using various transient overvoltage values.

Comparison of spark-over distances computed using Gallet wet equations
vs.
IEEE 516-2003 MAID distances
using various transient over-voltage factors

(AC) Nom System Voltage (kV)	(AC) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 5 IEEE 516 MAID (ft) @ Alt. 3000 feet
765	800	1.4	8.89	8.65
500	550	1.4	5.65	4.92
345	362	1.4	3.52	3.13
230	242	2.0	3.35	2.8
115	121	2.0	1.6	1.4

(AC) Nom System Voltage (kV)	(AC) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 5 (historical maximums) IEEE 516 MAID (ft) @ Alt. 3000 feet
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

(AC) Nom System Voltage (kV)	(AC) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 7 **IEEE 516 MAID (ft) @ Alt. 3000 feet**
765	800	2.5	20.25	20.4
500	550	3.0	15.02	14.7
345	362	3.5	10.42	9.44
230	242	3.5	6.32	5.14
115	121	3.5	2.90	2.45

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SC approved SAR for initial posting (January 11, 2007).
2. SAR posted for comment (January 15–February 14, 2007).
3. SAR posted for comment (April 10–May 9, 2007).
4. SC authorized moving the SAR forward to standard development (June 27, 2007).
5. First draft of proposed standard posted (October 27, 2008-November 25, 2008)).
6. Second draft of revised standard posted (September 10, 20-October 24, 2009).
7. Third draft of revised standard posted (March 1, 2010-March 31, 2010).
8. Forth draft of revised standard posted (June 17, 2010-July 17, 2010).

Proposed Action Plan and Description of Current Draft

This is the ~~second~~third posting of the proposed revisions to the standard in accordance with Results-Based Criteria and the fifth draft overall.

Future Development Plan

Anticipated Actions	Anticipated Date
~~Drafting team considers comments, makes conforming changes, and requests SC approval to proceed to formal comment and ballot.~~	~~June - July 2010~~
Recirculation ballot of standards.	~~July-August 2010~~January 2011
Receive BOT approval	~~August 2010~~February 2011

Effective Dates

~~1.~~ First calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory ~~authority~~authorities where such explicit approval ~~for all requirements~~
~~2. First calendar day of the first calendar quarter one year following Board of Trustees adoption unless governmental authority withholds approval~~
~~First calendar day of the first calendar quarter that~~ is ~~at least one year following Board of Trustees adoption~~required.

Exceptions:

A line operated below 200kV, designated by the Planning Coordinator as an element of an IROL or as a Major WECC transfer path, becomes subject to this standard 12 months after the date the Planning Coordinator or WECC initially designates the ~~lines~~line as being subject to this standard.

An existing transmission line operated at 200kV or higher that is newly acquired by an asset owner and was not previously subject to this standard, becomes subject to this standard 12 months after the acquisition date of the line.

Version History

Version	Date	Action	Change Tracking
1	TBA	1. Added “Standard Development Roadmap.” 2. Changed “60” to “Sixty” in section A, 5.2. 3. Added “Proposed Effective Date: April 7, 2006” to footer. 4. Added “Draft 3: November 17, 2005” to footer.	01/20/06
1	April 4, 2007	Regulatory Approval — Effective Date	New
2			

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary. When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.

Right-of-Way (ROW)

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.

> ~~The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.~~
>
> ~~Current definition of Vegetation Inspection: The systematic examination of a transmission corridor to document vegetation conditions.~~

Vegetation Inspection

The systematic examination of vegetation conditions on a ~~maintained transmission line Right-of-Way which~~Right-of-Way and those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

> The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.
>
> Current definition of Vegetation Inspection: The systematic examination of a transmission corridor to document vegetation conditions.

Introduction

1. **Title:** Transmission Vegetation Management

2. **Number:** FAC-003-2

3. **Objectives:** To ~~improve the reliability of the~~ maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

4. **Applicability**

4.1. Functional Entities:

Transmission Owners

4.2. Facilities: Defined below~~,~~ (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities:

4.2.1. Overhead transmission lines operated at 200kV or higher.

4.2.2. Overhead transmission lines operated below 200kV having been identified as included in the definition of an Interconnection Reliability Operating Limit (IROL) under NERC Standard FAC-014 by the Planning Coordinator.

4.2.3. Overhead transmission lines operated below 200 kV having been identified as included in the definition of one of the *Major WECC Transfer Paths in the Bulk Electric System*.

4.2.4. This standard ~~does not apply~~applies to ~~Facilities~~overhead transmission lines identified above (4.2.1 through 4.2.3) located ~~in~~outside the fenced area of ~~a~~the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

Rationale

-The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) The standard was written for Transmission Owners. Rolling the excluded areas into this standard will bring GO and DP into the standard, even though NERC has an initiative in place to address this bigger registry issue. 4) Specifically addressing the areas where the standard applies or doesn't makes the standard stronger as it relates to clarity.

4.3. Enforcement: *The reliability obligations of*

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies"*.

the applicable entities and facilities are contained within the technical requirements of this standard. [Straw proposal]

~~**4.4. Other:**~~

~~This Standard does not apply to any occurrence, non-occurrence, or other set of circumstances that are beyond the control of a Transmission Owner subject to this reliability standard, including acts of God, flood, drought, earthquake, major storms, fire, hurricane, tornado, landslides, ice storms, vehicle contact with tree, human activity involving: removal of, installation of, or digging around vegetation, animals severing trees, lightning, epidemic, strike, war, riot, civil disturbance, sabotage, vandalism, terrorism, wind shear, or fresh gale (or higher wind speed) that restricts or prevents performance to comply with this reliability standard's requirements. Nothing in this section should be construed to limit the Transmission Owner's right to exercise its full legal rights on the active transmission line ROW[2].~~

5. Background:

This NERC Vegetation Management Standard ("Standard") uses a defense-in-depth approach to improve the reliability of the electric Transmission System by preventing those vegetation related outages that could lead to Cascading. This Standard is not intended to address non-preventable outages such as those due to vegetation fall-ins or blow-ins from outside the ~~Active Transmission Line~~ Right-of-Way, vandalism, human activities and acts of nature. Operating experience indicates that trees that have grown out of specification have contributed to Cascading, especially under heavy electrical loading conditions.

With a defense-in-depth strategy, this Standard utilizes three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

a) Performance-based — defines a particular reliability objective or outcome to be achieved.

b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels.

c) Competency-based — defines a minimum capability an entity needs to have to demonstrate it is able to perform its designated reliability functions.

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard. For this Standard, the requirements have been developed as follows:

~~[2] A strip or corridor of land that is occupied by active transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities. However, it is not to be less than the width of the easement itself unless the easement exceeds distances as shown in Table 3 for various voltage classes.~~

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

Thus the various requirements associated with a successful vegetation program could be viewed as using R1, R2 and R3 as first levels of defense; while R4 could be a subsequent or final level of defense. R6 depending on the particular vegetation approach may be either an initial defense barrier or a final defense barrier.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the Standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the Standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.

This Standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This Standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this Standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of multiple line failures and Cascading. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are statistically intermittent. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this Standard’s emphasis is on vegetation grow-ins.

Requirements and Measures

R1. Each Transmission Owner shall manage vegetation to prevent ~~encroachment that could result in a Sustained Outage~~encroachments of the types shown below, into the Minimum Vegetation Clearance Distance (MVCD) of any of its applicable line(s) identified as an element of an Interconnection Reliability Operating Limit (IROL) in the planning horizon by the Planning Coordinator; or Major Western Electricity Coordinating Council (WECC) transfer path ~~(~~(s); operating within its Rating and all Rated Electrical Operating Conditions~~). Types of encroachment include:~~.[3]

1. An encroachment into the ~~Minimum Vegetation Clearance Distance (MVCD)~~ MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,
2. An encroachment due to a fall-in from inside the ~~active transmission line~~ Right-of-Way (ROW) that caused a vegetation-related Sustained Outage,
3. An encroachment due to blowing together of applicable lines and vegetation located inside the ~~active transmission line~~ ROW that caused a vegetation-related Sustained Outage,
4. An encroachment due to a grow-in that caused a vegetation-related Sustained Outage.

[VRF – High] [Time Horizon – Real-time]

Rationale

The MVCD is a calculated minimum distance stated in feet (meters) to prevent ~~spark~~flash-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method. The types of failure to manage vegetation are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO's vegetation maintenance program since the encroachments listed require different and increasing levels of skills and knowledge and thus constitute a logical progression of how well, or poorly, a TO manages vegetation relative to this Requirement.

M1. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments.

If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-

[3] This requirement does not apply to circumstances that are beyond the control of a Transmission Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

hour period.~~ If an investigation of a Fault by a qualified person confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered a Real-time observation.~~ (R1)

R2. Each Transmission Owner shall manage vegetation to prevent ~~encroachment that could result in a Sustained Outage of~~encroachments of the types shown below, into the MVCD of any of its applicable ~~lines~~line(s) that ~~are~~is not ~~elements~~an element of an ~~Interconnection Reliability Operating Limit (~~IROL~~)~~; or Major ~~Western Electricity Coordinating Council (~~WECC~~)~~ transfer path~~ (~~; operating within its Rating and all Rated Electrical Operating Conditions~~). Types of encroachment include:~~.[3]

1. An encroachment into the ~~Minimum Vegetation Clearance Distance (MVCD)~~MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,
2. An encroachment due to a fall-in from inside the~~ active transmission line~~ ROW that caused a vegetation-related Sustained Outage,
3. An encroachment due to blowing together of applicable lines and vegetation located inside the ~~active transmission line~~ ROW that caused a vegetation-related Sustained Outage,
4. An encroachment due to a grow-in that caused a vegetation-related Sustained Outage. *[VRF – Medium] [Time Horizon – Real-time]*

Rationale

The MVCD is a calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 ... a logical progression of how well, or poorly, a TO manages vegetation relative to this Requirement.

~~**Rationale**~~

~~The MVCD is a calculated minimum distance stated in feet (meters) to prevent spark-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method.~~

M2. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments.

If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. ~~If an investigation of a Fault by a qualified person confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered a Real-time observation.~~(R2)

R3. Each Transmission Owner shall ~~document the~~ have documented maintenance strategies or procedures~~,~~ or processes~~,~~ or specifications it uses to prevent the encroachment of vegetation into the MVCD~~. Such documentation will incorporate~~ of its applicable transmission lines that include(s) the following:

3.1 Accounts for the ~~dynamics~~movement of ~~a~~applicable transmission line ~~conductor's movement throughout its~~ conductors under their Facility Rating and all Rated Electrical Operating Conditions ~~and~~;

3.2 Accounts for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency~~, for the Transmission Owner's applicable lines.~~.

[VRF – Lower] [Time Horizon – Long Term Planning]

Rationale

The documentation provides a basis for evaluating the competency of the Transmission Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the Transmission Owner avoids vegetation-to-wire conflicts under all Rated Electrical Operating Conditions. See Figure 1 for an illustration of possible conductor locations.

~~**Rationale**~~

~~Provide a basis for evaluation on the intent and competency of the Transmission Owner in maintaining vegetation. There may be many acceptable approaches to maintain clearances. However, the Transmission Owner should be able to state what its approach is and how it conducts work to maintain clearances. See Figure 1 for an illustration of possible conductor locations.~~

M3. The maintenance strategies or procedures~~,~~ or processes~~,~~ or specifications provided demonstrate that the Transmission Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

R4. Each Transmission Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable transmission line when ~~qualified personnel confirm~~the Transmission Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment.

[VRF – Medium] [Time Horizon – Real-time]

~~**Rationale**~~

~~To ensure expeditious communication between qualified field personnel and proper operating personnel when a critical situation is confirmed. Qualified field personnel may include lineworkers and utility arborists.~~

M4. Each Transmission Owner that has a confirmed vegetation condition likely to cause a Fault at any moment~~, as confirmed by qualified personnel,~~ will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. ~~Each~~When a Transmission Owner ~~shall take corrective action when it~~ is constrained from performing ~~planned~~ vegetation work, ~~where a transmission line is put at potential risk due to~~ and the constraint may lead to a vegetation encroachment into the MVCD of its applicable transmission lines prior to the implementation of the next annual work plan then the Transmission Owner shall take corrective action to ensure continued vegetation management to prevent encroachments.

[VRF – Medium] [Time Horizon – Operations Planning]

M5. Each Transmission Owner has evidence of the corrective action taken for each constraint where ~~a~~an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, and evidence that a line was de-energized. (R5)

Rationale

Legal actions and other events may occur which result in constraints that prevent the Transmission Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the Transmission Owner to put interim measures in place, rather than do nothing.

The corrective action process is intended to

~~**Rationale**~~

~~Legal actions and other events may occur which result in constraints that prevent the Transmission Owner from performing planned vegetation maintenance work.~~

~~In cases where the transmission line is put at potential risk due to constraints, the intent is for the Transmission Owner to put interim measures in place, rather than do nothing.~~

~~For example, in the 2003 NE blackout a Transmission Owner was prevented by a court order from performing planned work. However, when the court order expired, the TO failed to take action to maintain the vegetation resulting in a sustained outage that contributed to the cascade.~~

~~The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.~~

R6. Each Transmission Owner shall perform a Vegetation Inspection of ~~all~~100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year~~.~~ and with no more than 18 months between inspections on the same ROW.[4]

Rationale

Inspections are used by Transmission Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year~~.~~ but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

[4] When the Transmission Owner is prevented from performing a [...] due to a natural disaster, the TO is granted a time extension that i[...] prevented from performing the Vegetation Inspection.

[VRF – Medium] [Time Horizon – Operations Planning]

~~*[VRF – Medium] [Time Horizon – Operations Planning]*~~

M6. Each Transmission Owner has evidence that it conducted Vegetation Inspections ~~at least once per calendar year~~ of the transmission line ROW for all applicable transmission lines at least once per calendar year but with no more than 18 months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each Transmission Owner shall complete ~~the work in an~~100% of its annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made ~~and documented (~~provided they do not put the transmission system at risk of a vegetation encroachment~~.~~) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include:

~~**Rationale**~~
~~This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. An annual vegetation work plan allows for work to be modified for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that the changes do not violate the encroachment within the MVCD.~~

- Change in expected growth rate/ environmental factors
- ~~Major storms~~
- Circumstances that are beyond the control of a Transmission Owner[5]
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- ~~Funding adjustments (increase or decrease)~~
- Emerging technologies

[VRF – Medium] [Time Horizon – Operations Planning]

[5] Circumstances that are beyond the control of a Transmission Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, major storms as defined either by the TO or an applicable regulatory body, ice storms, and floods; arboricultural, horticultural or agricultural activities.

~~*[VRF – Medium] [Time Horizon – Operations Planning]*~~

M7. Each Transmission Owner has evidence that it completed its annual vegetation work plan. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (including modifications if any), dated work orders, dated invoices, or dated inspection records. (R7)

Compliance

Compliance Enforcement Authority

- Regional Entity

Compliance Monitoring and Enforcement Processes:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints
- Periodic Data Submittals

Evidence Retention

The Transmission Owner retains data or evidence ~~of~~to show compliance with Requirements R1~~ through~~, R2, R3, R5, R6 and R7, Measures M1~~ through~~, M2, M3, M5, M6 and M7 for three calendar years ~~to show compliance~~unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant~~,~~ or for the ~~duration~~time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

Additional Compliance Information

Periodic Data Submittal: The Transmission Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable transmission lines determined by the Transmission Owner to have been caused by vegetation~~ that~~, except as excluded in footnote 2, which includes~~,~~ as a minimum, the following:

- o The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.

A Sustained Outage is to be categorized as one of the following:

- o Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable transmission lines, that are identified as an element of an IROL or

Major WECC Transfer Path, by vegetation inside and/or outside of the ~~active transmission line~~ ROW;

- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable transmission lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ~~active transmission line~~ ROW;
- Category ~~2~~2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable transmission lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ~~active transmission line~~ ROW;
- Category[6] ~~4~~ 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable transmission lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable transmission lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable transmission lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ~~active transmission line~~ROW.
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable transmission lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by Transmission Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

[6] ~~Category 3 reporting is eliminated.~~

~~At the request of the Standards Committee, stakeholders are asked to review and comment on the proposed VSLs for R1 and R2. Following the comment period and nonbinding poll, only one set of VSLs will move forward for R1 and R2.~~

Time Horizons, Violation Risk Factors, and Violation Severity Levels

Table 1

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1-~~SDT Version~~	Real-time	High	The Transmission Owner had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.	The Transmission Owner had an encroachment into the MVCD due to a fall-in from inside the ~~active transmission line~~ ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ~~active transmission line~~ ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner had an encroachment into the MVCD due to a grow-in that caused a vegetation-related Sustained Outage.
~~R1 Staff Version~~	~~Real-time~~	~~High~~			~~The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.~~	~~The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:~~ • ~~A fall-in from inside the active transmission line ROW~~ • ~~Blowing together of applicable lines and vegetation located inside the active transmission line ROW~~

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							~~A grow-in~~
R2~~- SDT Version~~		Real-time	Medium	The Transmission Owner had an encroachment into the MVCD observed in Real~~-~~time, absent a Sustained Outage.	The Transmission Owner had an encroachment into the MVCD due to a fall-in from inside the ~~active transmission line~~ ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ~~active transmission line~~ ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner had an encroachment into the MVCD due to a grow-in that caused a vegetation-related Sustained Outage.
~~R2 Staff Version~~		~~Real-time~~	~~Medium~~			~~The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and encroachment into the MVCD as identified in FAC-003-Table 2 was observed in real time absent a Sustained Outage.~~	~~The Transmission Owner failed to manage vegetation to prevent encroachment into the MVCD of a line not identified as an element of an IROL or Major WECC transfer path and a vegetation-related Sustained Outage was caused by one of the following:~~ • ~~A fall-in from inside the active transmission line ROW~~ • ~~Blowing together of applicable lines and vegetation located inside the active transmission line ROW~~ • ~~A grow-in~~
R3		Long-Term Planning	Lower		The Transmission Owner has maintenance strategies or documented ~~the~~ procedures~~,~~ or processes~~,~~ or specifications but ~~does~~has not ~~incorporate~~accounted for the inter-	The Transmission Owner has maintenance strategies or documented ~~the~~ procedures~~,~~ or processes~~,~~ or specifications but ~~does~~has	The Transmission Owner does not have any maintenance strategies or documented procedures~~,~~ or processes or specifications used to prevent

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				relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the Transmission Owner's applicable lines.	not ~~incorporate~~accounted for the ~~dynamics~~movement of ~~a~~ transmission line ~~conductor's movement throughout its~~conductors under their Rating and all Rated Electrical Operating Conditions, for the Transmission Owner's applicable lines.	the encroachment of vegetation into the MVCD, for the Transmission Owner's applicable lines.
R4	Real-time	Medium			The Transmission Owner experienced a confirmed vegetation threat ~~confirmed by qualified personnel~~ and notified the control center holding switching authority for that transmission line, but there was intentional delay in that notification.	The Transmission Owner experienced a confirmed vegetation threat ~~confirmed by qualified personnel~~ and did not notify the control center holding switching authority for that transmission line.
R5	Operations Planning	Medium				The Transmission Owner did not take corrective action when it was constrained from performing planned vegetation work where a transmission line was put at potential risk.
R6	Operations Planning	Medium	The Transmission Owner failed to inspect 5% or less of ~~the ROW as measured by~~its applicable~~- line miles~~	The Transmission Owner failed to inspect more than 5% up to and including 10% of ~~the ROW as measured by~~its applicable~~ line miles (kilometers) (based on~~ transmission lines (measured in units of choice~~:~~ - circuit, pole line, ~~ROW~~line miles or kilometers, etc.).	The Transmission Owner failed to inspect more than 10% up to and including 15% of ~~the ROW as measured by~~its applicable~~- line miles (kilometers) (based on~~ transmission lines (measured in units of choice~~:~~ - circuit, pole line, ~~ROW~~line miles or kilometers, etc.).	The Transmission Owner failed to inspect more than 15% of ~~the ROW as measured by~~its applicable~~ line miles (kilometers) (based on~~ transmission lines (measured in units of choice~~:~~ - circuit, pole line, ~~ROW~~line miles or kilometers, etc.).

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			~~(kilometers) (based on~~ transmission lines (measured in units of choice~~:~~ - circuit, pole line, ~~ROW~~line miles or kilometers, etc~~.)~~.)			
R7	Operations Planning	Medium	The Transmission Owner failed to complete up to 5% of its annual vegetation work plan (including modifications if any).	The Transmission Owner failed to complete more than 5% and up to 10% of its annual vegetation work plan (including modifications if any).	The Transmission Owner failed to complete more than 10% and up to 15% of its annual vegetation work plan (including modifications if any).	The Transmission Owner failed to complete more than 15% of its annual vegetation work plan (including modifications if any).

Variances

None.

Interpretations

None.

~~Guidelines~~Guideline and Technical Basis

Requirements R1 and R2:
R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the prevention of vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each Transmission Owner to ~~prevent~~manage vegetation ~~from encroaching~~to prevent encroachment within the Minimum Vegetation Clearance Distance ("MVCD") of transmission lines. R1 is applicable to lines "identified as an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions) to avoid a Sustained Outage". R2 applies to all other applicable lines that are not an element of an IROL or Major WECC Transfer Path.

The separation of applicability (between R1 and R2) recognizes that an encroachment into the MVCD of an IROL or Major WECC Transfer Path transmission line is a greater risk to the electric transmission system. Applicable lines that are not an element of an IROL or Major WECC Transfer Path are required to be clear of vegetation but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

These requirements (R1 and R2) state that if vegetation encroaches within the distances ~~prescribed~~ in Table 1 in Appendix 1 of this supplemental Transmission Vegetation Management Standard FAC-003-2 Technical Reference document, it is in violation of the standard. Table 2 ~~delineates~~tabulates the distances necessary to prevent spark-over based on the Gallet equations as described more fully in ~~a supplemental *Transmission Vegetation Management Standard FAC-003-2 Technical Reference*.~~Appendix 1 below.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating (potentially in violation of other standards), the occurrence of a clearance encroachment may occur. For example, emergency actions taken by a Transmission Operator or Reliability Coordinator to protect an Interconnection may cause the transmission line to sag more and come closer to vegetation, potentially causing an outage. Such vegetation-related outages are not a violation of these requirements.

Evidence of violation of Requirement R1 and R2 include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ~~active transmission line~~ ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to blowing together of applicable lines and vegetation located inside the ~~active transmission line~~ ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. If an investigation of a Fault by a ~~qualified person~~Transmission Owner confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered the equivalent of a Real-time observation.

With this approach, the VSLs were defined such that they directly correlate to the severity of a failure of a Transmission Owner to ~~keep~~manage vegetation ~~away from conductors~~ and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the goal of "preventing a Sustained Outage that could lead to Cascading." Thus violation severity increases with a Transmission Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation~~,~~. For example, a limb ~~that~~may only partially ~~breaks~~break and intermittently ~~contacts~~contact a conductor. Such events are considered to be a single vegetation-related Sustained Outage under the Standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will ~~help~~ prevent transmission outages.

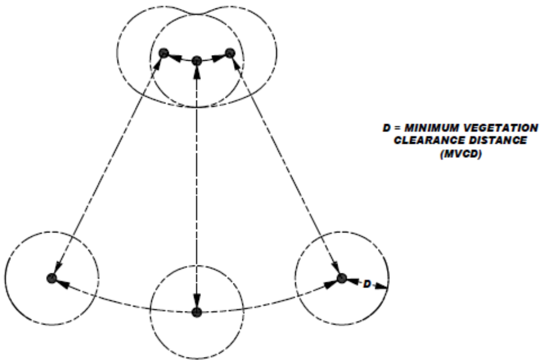
Requirement R3:
Requirement R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, a Transmission Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the Transmission Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the Transmission System. The approach provides the basis for evaluating the intent, allocation of appropriate resources and the competency of the Transmission Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the Transmission Owner must be able to state what its approach is and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach a Transmission Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the Transmission Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing as a reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below.



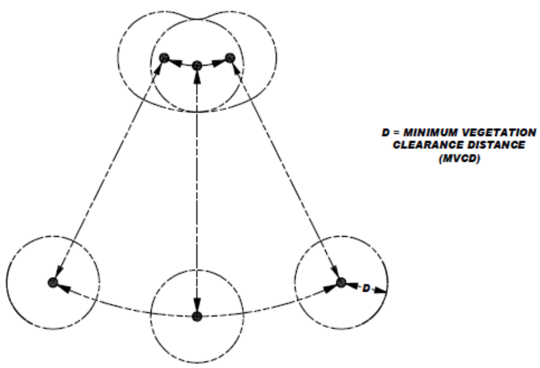


Figure 1
Cross-section view of a single conductor at a given point along the span showing six possible conductor positions due to movement resulting from thermal and mechanical loading.

Requirement R4:
R4 is a risk-based requirement. It focuses on preventative actions to be taken by the Transmission Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of a ~~qualified~~Transmission Owner's employee who personally identifies such a threat in the field. Confirmation could also be made by sending out ~~a qualified person~~an employee to evaluate a situation reported by a landowner~~ or an unqualified employee~~.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The Transmission Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or positioning the system in recognition of the increasing risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some Transmission Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5:
R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the Transmission Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the Transmission Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the Transmission Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the Transmission Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the Transmission Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the Transmission Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for each location.
- In developing the specific action to mitigate the potential risk to the transmission line the Transmission Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The Transmission Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:
R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections that fits general industry practice. In addition, the fact that Vegetation Inspections can be performed in conjunction with general line inspections further facilitates a Transmission Owner's ability to meet this requirement. However, the Transmission Owner may determine that more frequent inspections are needed to maintain reliability levels, dependent upon such factors as anticipated growth rates of the local vegetation, length of the growing season for the geographical area, limited ~~Active Transmission~~ ROW width, and rainfall amounts. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSL for Requirement R6 has VSL categories ranked by the percentage of the required ROW inspections completed. To calculate the percentage of inspection completion, the Transmission Owner may choose units such as: line miles or kilometers, circuit miles or kilometers, pole line miles, ROW miles, etc.

For example, when a Transmission Owner operates 2,000 miles of 230 kV transmission lines this Transmission Owner will be responsible for inspecting all 2,000 miles of 230 kV transmission lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

Requirement R7:
R7 is a risk-based requirement. The Transmission Owner is required to implement an annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections

may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a “span-by-span”, or even a “line-by-line” detailed description of all work to be performed. It is only intended to require that the Transmission Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

The ability to modify the work plan allows the Transmission Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the Transmission Owner’s system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan. Modifications to the annual work plan must always ensure the reliability of the electric Transmission system.

In general, the vegetation management maintenance approach should use the full extent of the Transmission Owner’s easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ~~active transmission line~~ ROW is superior to incremental management in the long term because it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the Transmission Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Transmission Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the Transmission Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[7]
For **Alternating Current** Voltages

(AC) Nominal System Voltage (kV)	**(AC) Maximum System Voltage (kV)**	**MVCD feet (meters) sea level**	**MVCD feet (meters) 3,000ft (914.4m)**	**MVCD feet (meters) 4,000ft (1219.2m)**	**MVCD feet (meters) 5,000ft (1524m)**	**MVCD feet (meters) 6,000ft (1828.8m)**	**MVCD feet (meters) 7,000ft (2133.6m)**	**MVCD feet (meters) 8,000ft (2438.4m)**	**MVCD feet (meters) 9,000ft (2743.2m)**	**MVCD feet (meters) 10,000ft (3048m)**	**MVCD feet (meters) 11,000ft (3352.8m)**
765	800	8.06ft (2.46m)	8.89ft (2.71m)	9.17ft (2.80m)	9.45ft (2.88m)	9.73ft (2.97m)	10.01ft (3.05m)	10.29ft (3.14m)	10.57ft (3.22m)	10.85ft (3.31m)	11.13ft (3.39m)
500	550	5.06ft (1.54m)	5.66ft (1.73m)	5.86ft (1.79m)	6.07ft (1.85m)	6.28ft (1.91m)	6.49ft (1.98m)	6.7ft (2.04m)	6.92ft (2.11m)	7.13ft (2.17m)	7.35ft (2.24m)
345	362	3.12ft (0.95m)	3.53ft (1.08m)	3.67ft (1.12m)	3.82ft (1.16m)	3.97ft (1.21m)	4.12ft (1.26m)	4.27ft (1.30m)	4.43ft (1.35m)	4.58ft (1.40m)	4.74ft (1.44m)
230	242	2.97ft (0.91m)	3.36ft (1.02m)	3.49ft (1.06m)	3.63ft (1.11m)	3.78ft (1.15m)	3.92ft (1.19m)	4.07ft (1.24m)	4.22ft (1.29m)	4.37ft (1.33m)	4.53ft (1.38m)
161*	169	2ft (0.61m)	2.28ft (0.69m)	2.38ft (0.73m)	2.48ft (0.76m)	2.58ft (0.79m)	2.69ft (0.82m)	2.8ft (0.85m)	2.91ft (0.89m)	3.03ft (0.92m)	3.14ft (0.96m)
138*	145	1.7ft (0.52m)	1.94ft (0.59m)	2.03ft (0.62m)	2.12ft (0.65m)	2.21ft (0.67m)	2.3ft (0.70m)	2.4ft (0.73m)	2.49ft (0.76m)	2.59ft (0.79m)	2.7ft (0.82m)
115*	121	1.41ft (0.43m)	1.61ft (0.49m)	1.68ft (0.51m)	1.75ft (0.53m)	1.83ft (0.56m)	1.91ft (0.58m)	1.99ft (0.61m)	2.07ft (0.63m)	2.16ft (0.66m)	2.25ft (0.69m)
88*	100	1.15ft (0.35m)	1.32ft (0.40m)	1.38ft (0.42m)	1.44ft (0.44m)	1.5ft (0.46m)	1.57ft (0.48m)	1.64ft (0.50m)	1.71ft (0.52m)	1.78ft (0.54m)	1.86ft (0.57m)
69*	72	0.82ft (0.25m)	0.94ft (0.29m)	0.99ft (0.30m)	1.03ft (0.31m)	1.08ft (0.33m)	1.13ft (0.34m)	1.18ft (0.36m)	1.23ft (0.37m)	1.28ft (0.39m)	1.34ft (0.41m)

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above).

[7] The distances in this Table are the minimums required to prevent ~~Flashover~~Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

Table 2 (cont.) — Minimum Vegetation Clearance Distances (MVCD)
For **Direct Current** Voltages

(DC) Nominal Pole to Ground Voltage (kV)	**MVCD feet (meters) sea level**	**MVCD feet (meters) 3,000ft (914.4m) Alt.**	**MVCD feet (meters) 4,000ft (1219.2m) Alt.**	**MVCD feet (meters) 5,000ft (1524m) Alt.**	**MVCD feet (meters) 6,000ft (1828.8m) Alt.**	**MVCD feet (meters) 7,000ft (2133.6m) Alt.**	**MVCD feet (meters) (8,000ft (2438.4m) Alt.**	**MVCD feet (meters) 9,000ft (2743.2m) Alt.**	**MVCD feet (meters) 10,000ft (3048m) Alt.**	**MVCD feet (meters) 11,000ft (3352.8m) Alt.**
±750	13.92ft (4.24m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.9ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.07ft (3.07m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	(13.54ft 4.13m)
±500	7.89ft (2.40m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	4.78ft (1.46m)	5.35ft (1.63m)	5.55ft (1.69m)	5.75ft (1.75m)	5.95ft (1.81m)	6.15ft (1.87m)	6.36ft (1.94m)	6.57ft (2.00m)	6.77ft (2.06m)	6.98ft (2.13m)
±250	3.43ft (1.05m)	4.02ft (1.23m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5ft (1.52m)	5.17ft (1.58m)

~~Table 3 – Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW~~

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 5 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 7 would have to be used. Table 7 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 242 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America [1].

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications.   The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.

The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations using various transient overvoltage values.

Comparison of spark-over distances computed using Gallet wet equations
vs.
IEEE 516-2003 MAID distances
using various transient over-voltage factors

~~69 - 138 kV~~ ~~139 - 230 kV~~(AC) ~~231 - 345 kV~~Nom System ~~346 - 500~~ Voltage (kV)	(AC) Max System Voltage (kV)	Transient Over-voltage Factor (T)	~~37.5 ft.~~ ~~50~~ Clearance (ft~~.~~.) ~~75 ft.~~Gallet (wet) ~~87.5 ft.~~@ Alt. 3000 feet	Table 5 IEEE 516 MAID (ft) @ Alt. 3000 feet
~~501 -~~ 765 ~~kV~~	800	1.4	~~100 ft.~~8.89	8.65
500	550	1.4	5.65	4.92
345	362	1.4	3.52	3.13
230	242	2.0	3.35	2.8
115	121	2.0	1.6	1.4

(AC) Nom System Voltage (kV)	(AC) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 5 (historical maximums) IEEE 516 MAID (ft) @ Alt. 3000 feet
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

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(AC) Nom System Voltage (kV)	(AC) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 7 IEEE 516 MAID (ft) @ Alt. 3000 feet
765	800	2.5	20.25	20.4
500	550	3.0	15.02	14.7
345	362	3.5	10.42	9.44
230	242	3.5	6.32	5.14
115	121	3.5	2.90	2.45

Implementation Plan for FAC-003-2

Prerequisite Approvals
There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

FAC-003-2 – Vegetation Management

Revision to Sections of Approved Standards and Definitions
There are no proposed revisions to requirements in other already approved standards. There are two revised definitions in the proposed standard. FAC-003-1 will be retired when FAC-003-2 becomes effective.

Compliance with Standard
The standard applies to Transmission Owners.

Effective Date
The effective date is the date entities are expected to meet the performance identified in this standard. The effective date allows entities time to make revisions to their existing transmission vegetation management programs to comply with the new requirements.

First calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval is required.

Exceptions:

A line operated below 200kV, designated by the Planning Coordinator as an element of an IROL or as a Major WECC transfer path, becomes subject to this standard 12 months after the date the Planning Coordinator or WECC initially designates the line as being subject to this standard.

An existing transmission line operated at 200kV or higher that is newly acquired by an asset owner and was not previously subject to this standard, becomes subject to this standard 12 months after the acquisition date of the line.

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RELIABILITY CORPORATION

Implementation Plan for FAC-003-2

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

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Compliance with Standard

The standard applies to Transmission Owners.

Effective Date

The effective date is the date entities are expected to meet the performance identified in this standard. The effective date allows entities time to make revisions to their existing transmission vegetation management programs to comply with the new requirements.

First calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory ~~authority~~authorities where such explicit approval ~~for all requirements~~is required.

~~1. First calendar day of the first calendar quarter one year following Board of Trustees adoption unless governmental authority withholds approval~~

~~First calendar day of the first calendar quarter that is at least one year following Board of Trustees adoption~~

Exceptions:

A line operated below 200kV, designated by the Planning Coordinator as an element of an IROL or as a Major WECC transfer path, becomes subject to this standard 12 months after the date the Planning Coordinator or WECC initially designates the line as being subject to this standard.

An existing transmission line operated at 200kV or higher that is newly acquired by an asset owner and was not previously subject to this standard, becomes subject to this standard 12 months after the acquisition date of the line.

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A. Introduction

1. **Title:** **Transmission Vegetation Management Program**

2. **Number:** FAC-003-1

3. **Purpose:** To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional Reliability Organizations (RRO) and the North American Electric Reliability Council (NERC).

4. **Applicability:**

   4.1. Transmission Owner.

   4.2. Regional Reliability Organization.

   4.3. This standard shall apply to all transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RRO as critical to the reliability of the electric system in the region.

5. **Effective Dates:**

   5.1. One calendar year from the date of adoption by the NERC Board of Trustees for Requirements 1 and 2.

   5.2. Sixty calendar days from the date of adoption by the NERC Board of Trustees for Requirements 3 and 4.

B. Requirements

R1. The Transmission Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the Transmission Owner's objectives, practices, approved procedures, and work specifications[1].

R1.1. The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the Transmission Owner's transmission lines.

R1.2. The Transmission Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the Transmission Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

R1.2.1. Clearance 1 — The Transmission Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner plans to return for future

[1] ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

R1.2.2. Clearance 2 — The Transmission Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These Transmission Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

R1.2.2.1 Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

R1.2.2.2 Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

R1.3. All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner, to perform their duties.

R1.4. Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

R1.5. Each Transmission Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

R2. The Transmission Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

R3. The Transmission Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission Owner to have been caused by vegetation.

R3.1. Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24-hour period.

R3.2. The Transmission Owner is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).

R3.3. The outage information provided by the Transmission Owner to the RRO, or the RRO's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.

R3.4. An outage shall be categorized as one of the following:

R3.4.1. Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;

R3.4.2. Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;

R3.4.3. Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

R4. The RRO shall report the outage information provided to it by Transmission Owner's, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the RRO as a result of any of the reported outages.

C. Measures

M1. The Transmission Owner has a documented TVMP, as identified in Requirement 1.

M1.1. The Transmission Owner has documentation that the Transmission Owner performed the vegetation inspections as identified in Requirement 1.1.

M1.2. The Transmission Owner has documentation that describes the clearances identified in Requirement 1.2.

M1.3. The Transmission Owner has documentation that the personnel directly involved in the design and implementation of the Transmission Owner's TVMP hold the qualifications identified by the Transmission Owner as required in Requirement 1.3.

M1.4. The Transmission Owner has documentation that it has identified any areas not meeting the Transmission Owner's standard for vegetation management and any mitigating measures the Transmission Owner has taken to address these deficiencies as identified in Requirement 1.4.

M1.5. The Transmission Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.

M2. The Transmission Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.

M3. The Transmission Owner has documentation that it has supplied quarterly outage reports to the RRO, or the RRO's designee, as identified in Requirement 3.

M4. The RRO has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

RRO

NERC

1.2. Compliance Monitoring Period and Reset

One calendar Year

1.3. Data Retention

Five Years

1.4. Additional Compliance Information

The Transmission Owner shall demonstrate compliance through self-certification submitted to the compliance monitor (RRO) annually that it meets the requirements of NERC Reliability Standard FAC-003-1. The compliance monitor shall conduct an on-site audit every five years or more frequently as deemed appropriate by the compliance monitor to review documentation related to Reliability Standard FAC-003-1. Field audits of ROW vegetation conditions may be conducted if determined to be necessary by the compliance monitor.

2. Levels of Non-Compliance

2.1. Level 1:

2.1.1. The TVMP was incomplete in one of the requirements specified in any subpart of Requirement 1, or;

2.1.2. Documentation of the annual work plan, as specified in Requirement 2, was incomplete when presented to the Compliance Monitor during an on-site audit, or;

2.1.3. The RRO provided an outage report to NERC that was incomplete and did not contain the information required in Requirement 4.

2.2. Level 2:

2.2.1. The TVMP was incomplete in two of the requirements specified in any subpart of Requirement 1, or;

2.2.2. The Transmission Owner was unable to certify during its annual self-certification that it fully implemented its annual work plan, or documented deviations from, as specified in Requirement 2.

2.2.3. The Transmission Owner reported one Category 2 transmission vegetation-related outage in a calendar year.

2.3. Level 3:

2.3.1. The Transmission Owner reported one Category 1 or multiple Category 2 transmission vegetation-related outages in a calendar year, or;

2.3.2. The Transmission Owner did not maintain a set of clearances (Clearance 2), as defined in Requirement 1.2.2, to prevent flashover between vegetation and overhead ungrounded supply conductors, or;

2.3.3. The TVMP was incomplete in three of the requirements specified in any subpart of Requirement 1.

2.4. Level 4:

2.4.1. The Transmission Owner reported more than one Category 1 transmission vegetation-related outage in a calendar year, or;

2.4.2. The TVMP was incomplete in four or more of the requirements specified in any subpart of Requirement 1.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
Version 1	TBA	1. Added “Standard Development Roadmap.” 2. Changed “60” to “Sixty” in section A, 5.2. 3. Added “Proposed Effective Date: April 7, 2006” to footer. 4. Added “Draft 3: November 17, 2005” to footer.	01/20/06

Unofficial Comment Form for 5th Draft of FAC-003-2 Transmission Vegetation Management —Project 2007-07 Vegetation Management

Please **DO NOT** use this form to submit comments. Please use the electronic form located at the site below to submit comments on the 5th Draft of FAC-003-2 Transmission Vegetation Management. Comments must be submitted by February 28, 2011.

http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

If you have questions please contact Doug Keegan or by telephone at 404-446-2576.

Draft 5 Information

On November 4, 2010 NERC staff provided a Quality Review of FAC-003-2 to the Standards Committee (SC). In November, 2010 the SC requested the VMSDT to work with NERC staff in addressing the items identified in the Quality Review, and approved posting of the revised documents. The SDT conducted several conference calls and acted in good faith to produce this Draft 5 of FAC-003-2. The VMSDT considered the feedback provided in the Quality Review by NERC staff and reached consensus in the following areas:

1. Elaborated upon the Purpose Statement to encompass more of the standard's content.
2. Added a Rationale text box to the 4.2 Facilities section, to explain the exclusion of substation facilities. Clarified 4.2.4 by adding specific boundary details.
3. Updated Requirement R1 and R2 to emphasize the "planning" time horizon as the applicable temporal context.
4. Elaborated upon the explanation in the Rationale text boxes for R1 and R2, to highlight the range of non-compliant performance.
5. Re-organized the content of Requirement R3 for improved readability.
6. Augmented Requirement R5 to include a "reliability objective."
7. Modified Requirement R6 and the associated VSLs for improved enforceability and for consistency in the units of measure between the Requirement and the associated VSLs.
8. Modified Requirement R7 and the associated VSLs for improved enforceability and for consistency in the units of measure between the Requirement and the associated VSLs.
9. Updated the Evidence Retention section in accordance with current guidelines.

Modification incorporated into this Draft 5 of FAC-003-2 in response to stakeholder comments include:

A. Removed reference to Active Transmission Line ROW.
B. Redefined the Glossary term for ROW to address Paragraph 734 of FERC Order 693 addressing the width of ROW to be maintained.
C. Redefined the Glossary term for Vegetation Inspection to include identifying hazards to the line inside the ROW.
D. Included the term referred to as "applicable lines" under 4.2 Facilities.
E. Removed 4.4 addressing "force majeure" under Applicability to Footnotes 2, 3 and 4.
F. In R1./R2 – M1/M2
   - Added reference "into the MVCD" into the text.

- Eliminated "types of encroachment" and added "The four types of failure to manage vegetation, in order of increasing severity."
- In M1/M2 Added a paragraph defining "later confirmation of a Fault by the TO as a real-time observation."
- Added Footnote 2
- Added to the Rationale box types of failures to manage vegetation.

G. In R4. Changed "qualified personnel" to TO.

H. In R5. Added the term "is constrained from performing vegetation work" and referenced MVCD.
   - Removed reference to 2003 NE blackout from Rationale box

I. In R6. added the phrase " but no more than 18 months between inspections" also added Footnote 3.

J. In R7. Replaced major storms bullet with "circumstances that are beyond the control of a Transmission Owner". Added Footnote 4 to this requirement.

K. In Additional Compliance Information
   - Category 2 was split into two parts recognizing IROL's and Major WECC Transfer Paths
   - Added Category 3 for Fall-ins from outside the ROW.
   - Category 4 was split into two parts recognizing IROL's and Major WECC Transfer Paths

L. Removed alternate versions of VSL's for R1./R2.

M. Deleted Table 3 from the Guidelines and Technical Basis section

Background Information

The purpose of Project 2007-07 Vegetation Management is to:

- Assist in providing an adequate level of reliability for the North American electric Transmission System by verifying that the FAC-003-2 Transmission Vegetation Management standard is complete and that its requirements are set at an appropriate level to ensure reliability.

- Incorporate other general improvements described in the Standard Review Guidelines to bring FAC-003-2 Transmission Vegetation Management into conformance with the latest version of the Reliability Standards Development Procedure and the ERO Sanctions Guidelines.

- Consider comments received from ERO regulatory authorities and stakeholders on FAC-003-1 Transmission Vegetation Management as noted in the NERC Standards Issues Database.

- Satisfy the requirement for review of FAC-003-2 Transmission Vegetation Management within five-year review cycle.

In addition, on January 14, 2010, the NERC Standards Committee endorsed the use of Project 2007-07 Vegetation Management as the prototype for the proof-of-concept for using the results-based criteria for developing a reliability standard. The results-based initiative is intended to focus the collective effort of NERC and industry participants on improving the clarity and quality of NERC reliability standards by developing performance-based, risk-based and competency-based requirements that accomplish a reliability objective through a defense-in-depth strategy, while eliminating documentation-driven requirements that do not have an impact on bulk power system reliability.

The Standards Committee also directed the standard drafting team for Project 2007-07 Vegetation Management to do so with a target for final industry ballot of draft FAC-003-2 Transmission Vegetation Management by August 31, 2010.

The criteria for developing a results-based reliability standard include:

1. Strive to achieve a portfolio of performance-based, risk-based, and competency-based mandatory reliability requirements that provide an effective defense-in-depth strategy for achieving an adequate level of reliability of the bulk power system.

    a) **Performance-based** — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome*?

    b) **Risk-based** — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome <u>that reduces a stated risk to the reliability of the bulk power system</u>?*

    c) **Competency-based** — defines a minimum capability an entity needs to have to demonstrate it is able to perform its designated reliability functions.

2. The defense-in-depth strategy for reliability standards development should recognize that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

3. Each requirement should identify a clear and measurable expected outcome, such as: i) a stated level of reliability performance, ii) a reduction in a specified reliability risk, or iii) a necessary competency.

4. Strive to minimize prescriptive, administrative (document something), and commercial requirements within the set of NERC reliability standards (i.e., these types of requirements are permissible in standards but should be the exception rather than the rule).

5. A requirement should not prescribe commercial business practices which do not contribute directly to reliability.

The Vegetation Management Standard Drafting Team worked with Ivy Hooks of Compliance Automation, Inc. to apply the "results-based" approach to developing requirements that are clear and enforceable. Ivy is the CEO of Compliance Automation and has shared a wealth of knowledge and expertise with the drafting team. The "look and feel" of the proposed standard contains much more information than we have been including in previous standards, thus the look and feel of the draft FAC-003-2 Transmission Vegetation Management standard is quite different from the look of our existing standards. One of the more obvious changes is the addition of information to aid end users in reading the requirements from a common understanding of the standard's objective and the rationale for including each requirement. During the Three-year Performance Assessment, stakeholders indicated that they wanted more information to assist in applying standards – and the additional details provided in the proposed Vegetation Management standard provide an example of one way to fill that void.

On February 11, 2010 the Standards Committee authorized the standard drafting team for Project 2007-07 Vegetation Management to take the following actions relative to the development of draft FAC-003-2 Transmission Vegetation Management:

- Discontinue work in developing a complete Consideration of Comments Report for the comments received in response to the posting of the second draft of the draft FAC-003-2 Transmission Vegetation Management standard that was posted in August 2009; however, post the comments received along with a summary of the actions taken by the team in response to those comments but without an individual response to each comment provided.
- Use informal comment periods to collect comments on future "drafts" of the standard, post the comments received during the informal comment periods along with a summary of how the team used the comments received and a redline version of the standard showing the changes made based on the comments received.
- Conduct a 45-day formal comment period in parallel with the formation of the ballot pool and the initial ballot of the standard; post the comments from the formal comment period as they are received for at least the first 30 days of the comment period.
- Use a standard template that is different from the template stipulated in the Reliability Standard Development Procedure as provided by the Standards Committee's Process Subcommittee.

With respect to the first bullet above, that work was completed with the March 1, 2010 posting. With respect to the second bullet above, this current posting is the second informal posting for comments, and the current plans are for the next posting to be a formal posting. A summary of the SDT considerations for the responses to the March 1, 2010 submittal has been posted on the NERC website in lieu of a full Consideration of Comments Report.

The following questions will assist the SDT in finalizing the development of FAC-003-2 Transmission Vegetation Management. For questions where you agree with indicated statement, please state that you agree. If you disagree with the statement, please explain why you disagree and provide a rationale, or alternate language, to support your position. We would appreciate answers to as many of the following questions as possible.

1. The SDT proposes a revised NERC Glossary definition for Right-of-Way (ROW). This revised definition will be used in lieu of the Active Transmission Line ROW. Do you agree? If answer is no, please explain.

   ☐ Yes
   ☐ No
   Comments:

2. In R1 and R2 and their associated VSLs, the SDT added the phrase *"in order of increasing severity"* and added the sentence, *"The types of encroachments are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO's vegetation maintenance program."* to the Rationale boxes for R1/R2. Do you agree? If answer is no, please explain.

   ☐ Yes

☐ No

Comments:

3. In response to comments received regarding t*he term "investigation" in M1/M2,* the SDT substituted *"confirmation…by the Transmission Owner..." in its place, among other minor edits to these measures.* Do you agree? If answer is no, please explain.

☐ Yes

☐ No

Comments:

4. In response to comments received that requirement R3 is unclear with respect to intent, the SDT added "maintenance strategies." Do you agree this clarifies the intent? If answer is no, please offer alternative language.

☐ Yes

☐ No

Comments:

5. The SDT added clarifying language in M7 to explain how the annual work plan percentage complete calculation is to be performed. Is this adequate? If no, please provide improved examples.

☐ Yes

☐ No

Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Transmission Vegetation Management
Standard FAC-003-2 Technical Reference

Prepared by the

North American Electric Reliability Corporation

Vegetation Management Standard Drafting Team

December 17, 2010

Introduction

This document is intended to provide supplemental information and guidance for complying with the requirements of Reliability Standard FAC-003-2.

The purpose of the Standard is to improve the reliability of the electric transmission system by preventing those vegetation related outages that could lead to Cascading.

Compliance with the Standard is mandatory and enforceable.

Special Note: The Application of Results-Based Approach to FAC-003-2

In its three-year assessment as the ERO, NERC acknowledged stakeholder comments and committed to:

i) addressing quality issues to ensure each reliability standard has a clear statement of purpose, and has outcome-focused requirements that are clear and measurable; and
ii) eliminating requirements that do not have an impact on bulk power system reliability.

In 2010, the Standards Committee approved a recommendation to use Project 2007-07 Vegetation Management as a first proof of concept for developing results-based standards.

The Standard Drafting Team (SDT) employed a defense-in-depth[1] strategy for FAC-003-2, where each requirement has a role in preventing those vegetation related outages that could lead to Cascading. This portfolio of requirements was designed to achieve an overall defense-in-depth strategy and to comply with the quality objectives identified in the *Acceptance Criteria of a Reliability Standard* document.

The SDT developed a portfolio of performance, risk, and competency-based mandatory reliability requirements to support an effective defense-in-depth strategy. Each Requirement was developed using one of the following requirement types:

a) Performance-based - defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?
b) Risk-based - preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?
c) Competency-based - defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

The drafting team reviewed and edited version 1 of FAC-003-1 to remove prescriptive and administrative language in order to distill the technical requirements down to their

[1] A defense-in-depth strategy for reliability standards recognizes that each requirement in the NERC standards has a role in preventing system failures, and that these roles are complementary and reinforcing. These prevention measures should be arranged in a series of defensive layers or walls. No single defensive layer provides complete protection from failure by itself. But taken together, with well-designed layers including performance, risk, and competency-based requirements, a defense-in-depth approach can be very effective in preventing future large scale power system failures.

essential reliability content. Text that is explanatory in nature is placed in a special section of the standard entitled Guideline and Technical Basis to aid in the understanding of the requirements. Furthermore, Rationale text boxes are inserted alongside each requirement to communicate the foundation for the requirement.

Disclaimer

This supporting document is supplemental to the reliability standard FAC-003-2 — Transmission Vegetation Management and does not contain mandatory requirements subject to compliance review.

Preface

The NERC Vegetation Management Standard Drafting Team (VM SDT) acknowledges those across the industry who contributed to the development of this Standard and companion Technical Reference document. The Technical Reference document is intended to provide supplemental explanatory background and guidance related to requirements contained in the Standard but does not in itself contain requirements subject to compliance review.

The VM SDT believes that a well-designed and executed Transmission Vegetation Management Program (TVMP) will have few problems meeting the requirements of this Standard. While the Standard requires a TVMP to contain certain elements, it allows the Transmission Owner flexibility in designing a TVMP to meet local needs provided it also meets the purpose of the Standard.

While there are many approaches to vegetation management, the VMSDT supports industry best practices contained in ANSI A300 (Part 7) – Integrated Vegetation Management (IVM) practices on Utility Rights-of-way, as well as the companion publication Best Management Practices – Integrated Vegetation Management, as an effective strategy to maintain compliance with this Standard. ANSI A300 (Part 7), approved by industry consensus in 2006, contains many elements needed for an effective TVMP as required by this Standard. One key element is the “wire zone – border zone” concept. Supported by over 50 years of continuous research, wire zone – border zone is a proven method to manage vegetation on transmission rights-of-ways and is an industry accepted best practice to help ensure electric system reliability.

The VM SDT believes that Transmission Owners who adopt and effectively implement IVM principles, particularly the “wire zone – border zone” concept, are far less likely to experience a vegetation caused outage than those who do not.

Definition of Terms

Right-of-Way (ROW)*

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.

The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

The current NERC glossary definition of Right of Way has been modified to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of "right of way" in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis.

Vegetation Inspection*

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.

Current definition of Vegetation Inspection: The systematic examination of a transmission corridor to document vegetation conditions.

The inspection includes the identification of any vegetation that may pose a threat to reliability prior to the next planned maintenance or inspection work, considering the current location of the conductor and other possible locations of the conductor due to sag and sway for rated conditions.

This definition allows both maintenance inspections and vegetation inspections to be performed concurrently.

* This is a modification to a defined term in the NERC glossary and will be incorporated into the NERC glossary of terms with final approval of this standard revision

Applicability of the Standard

4. Applicability

4.1. Functional Entities:
Transmission Owners

4.2. Facilities: *Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal*[1]*, state, provincial, public, private, or tribal entities:*

4.2.1 *Overhead transmission lines operated at 200kV or higher.*
4.2.2 *Overhead transmission lines operated below 200kV having been identified as included in the definition of an Interconnection Reliability Operating Limit (IROL) under NERC Standard FAC 014 by the Planning Coordinator.*
4.2.3 *Overhead transmission lines operated below 200 kV having been identified as included in the definition of one of the Major WECC Transfer Paths in the Bulk Electric System.*
4.2.4 *This standard applies to overhead transmission lines identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.*

4.3. Enforcement: *The reliability obligations of the applicable entities and facilities are contained within the technical requirements of this standard. [Straw proposal]*

Rationale

-The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) The standard was written for Transmission Owners. Rolling the excluded areas into this standard will bring GO and DP into the standard, even though NERC has an initiative in place to address this bigger registry issue. 4) Specifically addressing the areas where the standard applies or doesn't makes the standard stronger as it relates to clarity.

In Order 693, FERC discussed the 200 kV bright-line test of applicability. While FERC did not change the 200 kV bright line, the Commission remained concerned that there may be some transmission lines operating at lesser voltages that could have significant impact on the Bulk Electric System that should therefore be subject to this standard.

NERC Standard FAC-014 has the stated purpose, "*To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.*" FAC-014 requires Reliability Coordinators, Planning Coordinators, and Transmission Planners to have a methodology to identify all lines that might comprise an IROL. Thus, these entities would identify sub-200 kV lines that qualify as part of an IROL and should be subject to FAC-003-2.

[1] EPAct 2005 section 1211c: "*Access approvals by Federal agencies*".

Although all three entities may prepare the list of elements, FAC-003-2 presently does not specify that it is the list from the Planning Coordinator that should be used by Transmission Owners for FAC-003. However, the Time Horizon needed to plan vegetation management work does not lend itself to the operating horizon of a Reliability Coordinator. Additionally, the Planning Coordinator has a wider-area view than the Transmission Planner and could thus identify any elements of importance to a sub-set of its area that might be missed by a Transmission Planner.

Transmission Owners, who do not already get the list of circuits included in the definition of an IROL, can get them from the Planning Coordinator. Specifically R5 of FAC-014 specifies that "*The Reliability Coordinator, Planning Authority (Coordinator) and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits*"

Vegetation-related Sustained Outages that occur due to natural disasters are beyond the control of the Transmission Owner. These events are not classified as vegetation-related Sustained Outages and are therefore exempt from the Standard. Transmission lines are not designed to withstand the impacts of natural disasters such as flood, drought, earthquake, major storms, fire, hurricane, tornado, landslides, ice storms, etc. In the aftermath of catastrophic system damage from natural disasters the Transmission Owner's focus is on electric system restoration for public safety and critical support infrastructure.

Sustained Outages due to human or animal activity are beyond the control of the Transmission Owner. These outages are not classified as vegetation-related Sustained Outages and are therefore exempt from the Standard. Examples of these events may include new plantings by outside parties of tall vegetation under the transmission line planted since the last Vegetation Inspection, tree contacts with line initiated by vehicles, logging activities, etc.

The foregoing exemptions are addressed in a new footnote 2. Referred to collectively as force majeure events and activities, this footnote applies to requirements R1 and R2 in FAC-003-2.

The reliability objective of this NERC Vegetation Management Standard ("Standard") is to prevent vegetation-related outages which could lead to Cascading by effective vegetation maintenance while recognizing that certain outages such as those due to vandalism, human errors and acts of nature are not preventable. Operating experience clearly indicates that trees that have grown out of specification could contribute to a cascading grid failure, especially under heavy electrical loading conditions.

Serious outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. To properly reduce and manage this risk, it is necessary to apply the Standard to applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee. For the purposes of the Standard and this Technical Reference document, the term "public lands" includes municipal lands, village lands, city lands, and land owned by a host of other governmental entities.

The Standard addresses vegetation management along applicable overhead lines that serve to connect one electric station to another. However, it is not intended to be applied to lines sections inside the electric station fence or other boundary of an electric station, submarine or underground lines.

The Standard is intended to reduce the risk of Cascading involving vegetation. It is not intended to prevent customer outages from occurring due to tree contact with all transmission lines and voltages. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this Standard is not written to address such isolated situations which have little impact on the overall Bulk Electric System.

Vegetation growth is constant and always present. Unmanaged vegetation poses an increased outage risk when numerous transmission lines are operating at or near their Rating. This poses a significant risk of multiple line failures and Cascading. On the other hand, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are statistically intermittent. The probability of occurrence of these events is not dependent on heavy loads. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures.

In preparing the original vegetation management standard in 2005, industry stakeholders set the threshold for applicability of the standard at 200kV. This was because an unexpected loss of lines operating at above 200kV has a higher probability of initiating a widespread blackout or cascading outages compared with lines operating at less than 200kV.

The original NERC Standard FAC-003-1 also allowed for application of the standard to “critical” circuits (critical from the perspective of initiating widespread blackouts or cascading outages) operating below 200kV. While the percentage of these circuits is relatively low, it remains a fact that there are sub-200kV circuits whose loss could contribute to a widespread outage. Given the very limited exposure and unlikelihood of a major event related to these lower-voltage lines, it would be an imprudent use of resources to apply the Standard to all sub-200kV lines. The drafting team, after evaluating several alternatives, selected the IROL and WECC Major Transfer Path criteria to determine applicable lines below 200 kV that are subject to this standard.

Requirements R1 and R2

Rationale

Rationale

The MVCD is a calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method. The types of failure to manage vegetation are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO's vegetation maintenance program since the encroachments listed require different and increasing levels of skills and knowledge and thus constitute a logical progression of how well, or poorly, a TO manages vegetation relative to this Requirement.

R1. *Each Transmission Owner shall manage vegetation to prevent encroachments of the types shown below, into the Minimum Vegetation Clearance Distance (MVCD) of any of its applicable line(s) identified as an element of an Interconnection Reliability Operating Limit (IROL) in the planning horizon by the Planning Coordinator; or Major Western Electricity Coordinating Council (WECC) transfer path(s); operating within its Rating and all Rated Electrical Operating Conditions.*[2]

1. *An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,*
2. *An encroachment due to a fall-in from inside the Right-of-Way (ROW) that caused a vegetation-related Sustained Outage,*
3. *An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,*
4. *An encroachment due to a grow-in that caused a vegetation-related Sustained Outage. [VRF – High] [Time Horizon – Real-time]*

R2. *Each Transmission Owner shall manage vegetation to prevent encroachments of the types shown below, into the MVCD of any of its applicable line(s) that is not an element of an IROL; or Major WECC transfer path; operating within its Rating and all Rated Electrical Operating Conditions.*Error! Bookmark not defined.

1. *An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,*
2. *An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage,*
3. *An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage,*

[2] This requirement does not apply to circumstances that are beyond the control of a Transmission Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

4. *An encroachment due to a grow-in that caused a vegetation-related Sustained Outage.* *[VRF – Medium] [Time Horizon – Real-time]*

M1. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments.

If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. (R1)

M2. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments.

If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. (R2)

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the prevention of vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each Transmission Owner to manage vegetation to prevent encroachment within the Minimum Vegetation Clearance Distance ("MVCD") of transmission lines. R1 is applicable to lines "identified as an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions) to avoid a Sustained Outage". R2 applies to all other applicable lines that are not an element of an IROL or Major WECC Transfer Path.

The separation of applicability (between R1 and R2) recognizes that an encroachment into the MVCD of an IROL or Major WECC Transfer Path transmission line is a greater risk to the electric transmission system. Applicable lines that are not an element of an IROL or Major WECC Transfer Path are required to be clear of vegetation but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

These requirements (R1 and R2) state that if vegetation encroaches within the distances in Table 1 in Appendix 1 of this supplemental Transmission Vegetation Management Standard FAC-003-2 Technical Reference document, it is in violation of the standard. Table 2 tabulates the distances necessary to prevent spark-over based on the Gallet equations as described more fully in Appendix 1 below.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating (potentially in violation of other standards), the occurrence of a clearance encroachment may occur. For example, emergency actions taken by a Transmission Operator or Reliability Coordinator to protect an Interconnection may cause the transmission line to sag more and come closer to vegetation, potentially causing an outage. Such vegetation-related outages are not a violation of these requirements.

Evidence of violation of Requirement R1 and R2 include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to blowing together of applicable lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. If an investigation of a Fault by a Transmission Owner confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered the equivalent of a Real-time observation.

With this approach, the VSLs were defined such that they directly correlate to the severity of a failure of a Transmission Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the goal of "preventing a Sustained Outage that could lead to Cascading." Thus violation severity increases with a Transmission Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example, a limb may only partially break and intermittently contact a conductor. Such events are considered to be a single vegetation-related Sustained Outage under the Standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

Requirement R3

Rationale

The documentation provides a basis for evaluating the competency of the Transmission Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the Transmission Owner avoids vegetation-to-wire conflicts under all Rated Electrical Operating Conditions. See Figure 1 for an illustration of possible conductor locations.

R3. *Each Transmission Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable transmission lines that include(s) the following:*

3.1 *Accounts for the movement of applicable transmission line conductors under their Facility Rating and all Rated Electrical Operating Conditions;*

3.2 *Accounts for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.*

[VRF – Lower] [Time Horizon – Long Term Planning]

M3. *The maintenance strategies or procedures or processes or specifications provided demonstrate that the Transmission Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)*

Requirement R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, a Transmission Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the Transmission Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the Transmission System. The approach provides the basis for evaluating the intent, allocation of appropriate resources and the competency of the Transmission Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the Transmission Owner must be able to state what its approach is and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach a Transmission Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the Transmission Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing as a reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figures 2 and 3 below.

Conductor Dynamics

In order for a Transmission Owner to develop a specific maintenance approach, it is important to understand the dynamics of a line conductor's movement. This paper will first address the complexities inherent in observing and predicting conductor movement, particularly for field personnel. It will then present some examples of maintenance approaches which Transmission Owners may consider that take into account these complexities, while resulting in practical approaches for field personnel.

Additionally, it is important the Transmission Owner consider all conductor locations, the MVCD, and vegetation growth between maintenance activities when developing a maintenance approach.

Understanding Conductor Position and Movement

The conductor's position in space at any point in time is continuously changing as a reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading.

As a consequence of these loading variables, the conductor's position in space is dynamic and moving. When calculating the range of conductor positions, the Transmission Owner should use the same design criteria and assumptions that the Transmission Owner uses when establishing Ratings and SOL, as described in other standards. Typically, the greatest conductor movement would be at mid-span. As the conductor moves through various positions, a spark-over zone surrounding the conductor moves with it. The radius of the spark-over zone may be found by referring to Table 1 ("Minimum Vegetation Clearance Distances") in the standard. For illustrations of this zone and conductor movements, Figures 1 through 3 below demonstrate these concepts. At the time of making a field observation, however, it is very difficult to precisely know where the conductor is in relation to its wide range of all possible positions. Therefore, Transmission Owners must adopt maintenance approaches that account for this dynamic situation.

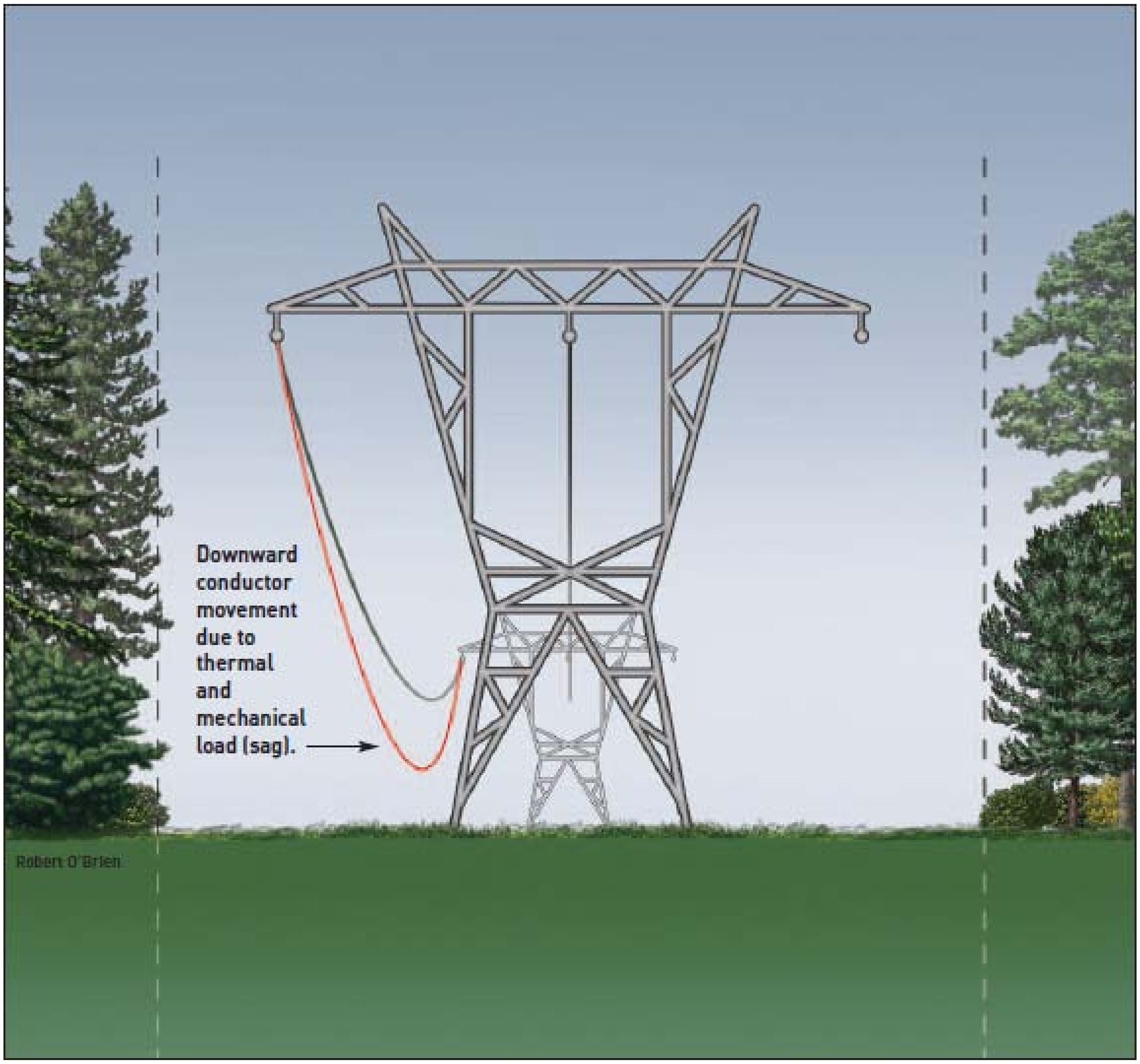

Downward
conductor
movement
due to
thermal
and
mechanical
load (sag).
Robert O'Brien

Figure 1

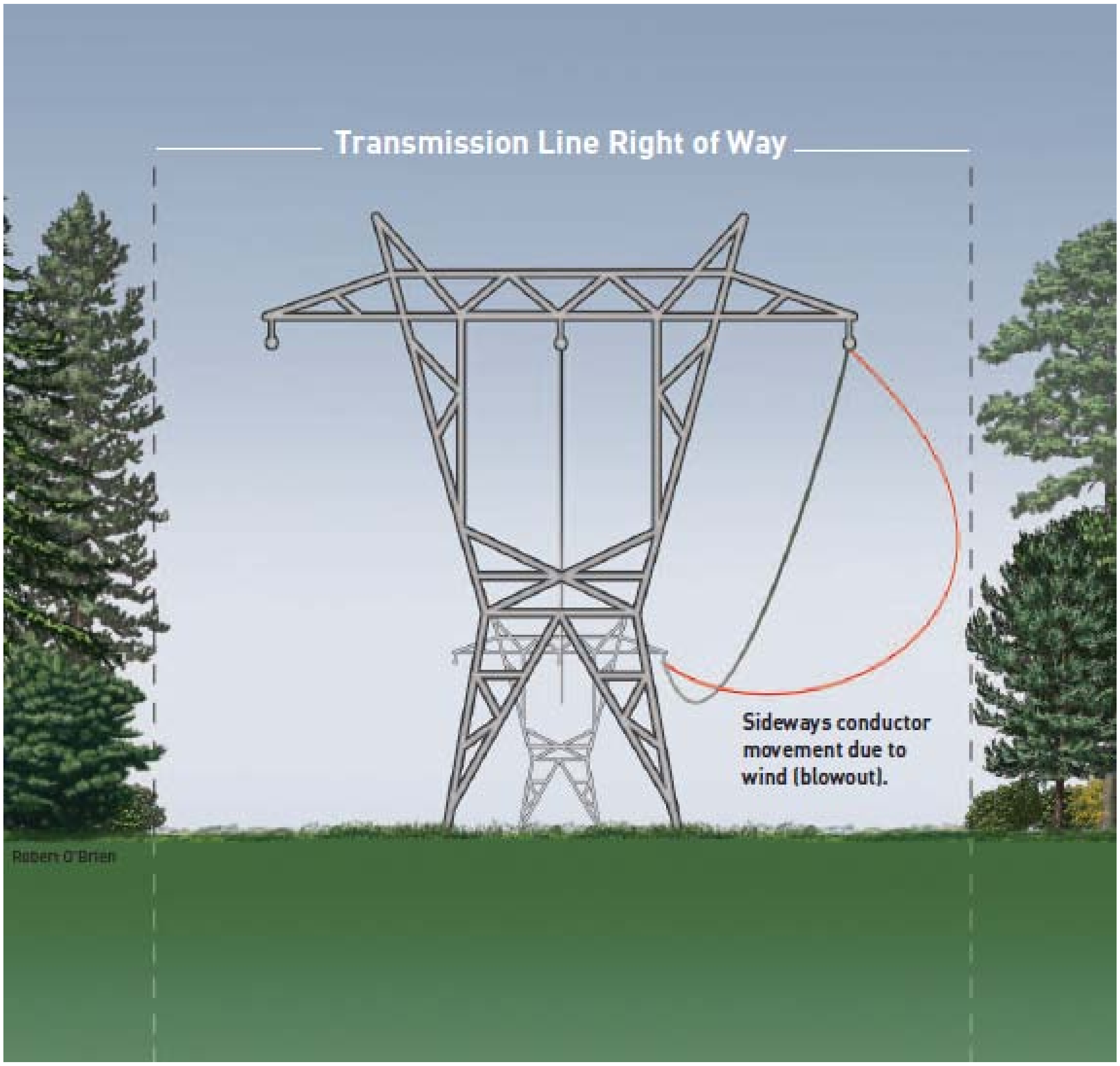
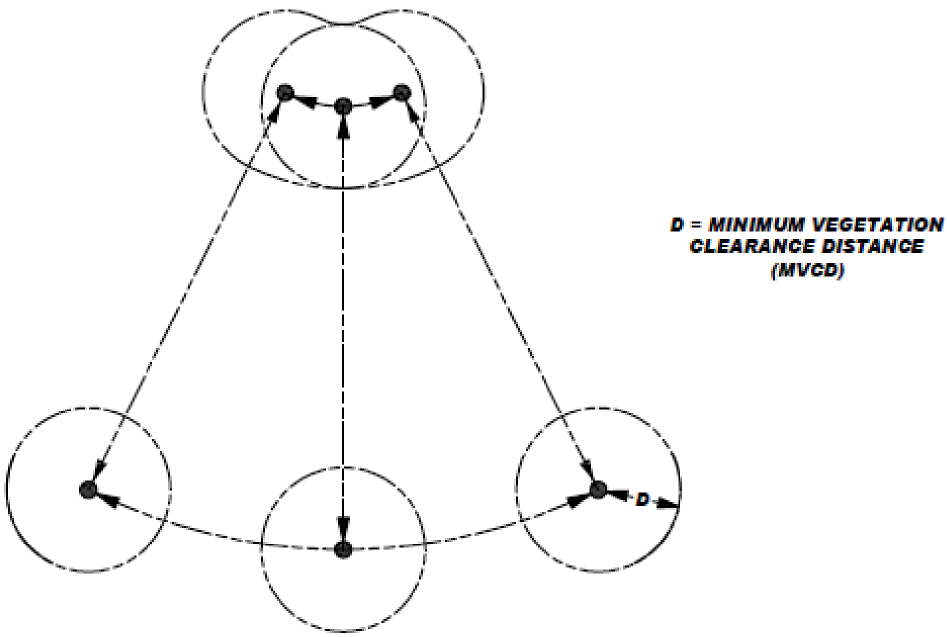

Transmission Line Right of Way
Sideways conductor movement due to wind (blowout).
Robert O'Brien

Figure 2



Cross-Section View of a Single Conductor

At a Given Point Along The Span

Showing Six Possible Conductor Positions Due to Movement

Resulting From Thermal and Mechanical Loading

For Consideration in Developing a Maintenance Approach

Figure 3

Selecting a Maintenance Approach

In order to maintain adequate separation between vegetation and transmission line conductors, the Transmission Owner must craft a maintenance strategy that keeps vegetation well away from the spark-over zone mentioned above. In fact, it is generally necessary to incorporate a variety of maintenance strategies. For example, one Transmission Owner may utilize a combination of routine cycles, traditional IVM techniques and long-term planning. Another Transmission Owner may place a higher reliance on frequent inspections and quick remediation as opposed to a cyclical approach. This variation of approaches is further warranted when factors, such as terrain, legal and other constraints, vegetation types, and climates, are considered in developing a Transmission Owner's specific approach to satisfying this requirement.

The following is a sample description of one combination of strategies which may be utilized by a Transmission Owner. A Transmission Owner's basic maintenance approach could be to remove all incompatible vegetation from the right of way if it has the right to do so and has no constraints. In mountainous terrain, however, this strategy could change to one where the Transmission Owner manages vegetation based on vegetation-to-conductor clearances, since it might not be necessary to remove vegetation in a valley that is far below.
If faced with constraints and assuming a line design with sufficient ground clearance, the Transmission Owner 's approach could then be to allow vegetation such as fruit trees, but perhaps only up to a given height at maturity (perhaps 10 feet from the ground). If constraints cannot be overcome and if design clearances are sufficient, an exception to the Transmission Owner's 10-foot guideline might be made. Finally, if the Transmission Owner has chosen to utilize vegetation-to-conductor clearance distance methods, the Transmission Owner could have an inspection regimen in place to regularly ensure that any impending clearance problems are identified early for rectification.

ANSI A300 – Best Management Practices for Tree Care Operations

A description of ANSI A-300, part 7, is offered below to illustrate another maintenance approach that could be used in developing a comprehensive transmission vegetation management program.

Introduction

Integrated Vegetation Management (IVM) is a best management practice conveyed in the American National Standard for Tree Care Operations, Part 7 (ANSI 2006) and the International Society of Arboriculture *Best Management Practices: Integrated Vegetation Management* (Miller 2007). IVM is consistent with the requirements in FAC-003-02, and it provides practitioners with what industry experts consider to be appropriate techniques to apply to electric right-of-way projects in order to meet or exceed the Standard.

IVM is a system of managing plant communities whereby managers set objectives; identify compatible and incompatible vegetation; consider action thresholds; and evaluate, select and implement the most appropriate control method or methods to achieve set objectives. The choice of control method or methods should be based on the environmental impact and anticipated effectiveness; along with site characteristics, security, economics, current land use and other factors.

Planning and Implementation

Best management practices provide a systematic way of planning and implementing a vegetation management program. While designed primarily with transmission systems in mind, it is also

applicable to distribution projects. As presented in ANSI A300 part 7 and the ISA best management practices, IVM consists of 6 elements:

1) Set Objectives
2) Evaluate the Site
3) Define Action Thresholds
4) Evaluate and Select Control Methods
5) Implement IVM
6) Monitor Treatment and Quality Assurance

The setting of objectives, defining action thresholds, and evaluating and selecting control methods all require decisions. The planning and implementation process is cyclical and continuous, because vegetation is dynamic and managers must have the flexibility to adjust their plans. Adjustments may be made at each stage as new information becomes available and circumstances evolve.

Set Objectives

Objectives should be clearly defined and documented. Examples of objectives can include promoting safety, preventing sustained outages caused by vegetation growing into electric facilities, maintaining regulatory compliance, protecting structures and security, restoring electric service during emergencies, maintaining access and clear lines of sight, protecting the environment, and facilitating cost effectiveness.

Objectives should be based on site factors, such as workload and vegetation type, in addition to human, equipment and financial resources. They will vary from utility to utility and project to project, depending on line voltage and criticality, as well as topographical, environmental, fiscal and political considerations. However, where it is appropriate, the overriding focus should be on environmentally-sound, cost effective control of species that potentially conflict with the electric facility, while promoting compatible, early successional, sustainable plant communities.

Work Load Evaluations

Work-load evaluations are inventories of vegetation that could have a bearing on management objectives. Work load assessments can capture a variety of vegetation characteristics, such as location, height, species, size and condition, hazard status, density and clearance from conductors. Assessments should be conducted considering voltage, conductor sag from ambient temperatures and loading, and the potential influence of wind on line sway.

Evaluate and Select Control Methods

Control methods are the process through which managers achieve objectives. The most suitable control method best achieves management objectives at a particular site. Many cases call for a combination of methods. Managers have a variety of controls from which to choose, including manual, mechanical, herbicide and tree growth regulators, biological, and cultural options.

Manual Control Methods

Manual methods employ workers with hand-carried tools, including chainsaws, handsaws, pruning shears and other devices to control incompatible vegetation. The advantage of manual techniques is that they are selective and can be used where others may not be. On the other hand, manual techniques can be inefficient and expensive compared to other methods.

Mechanical Control Methods

Mechanical controls are done with machines. They are efficient and cost effective, particularly for clearing dense vegetation during initial establishment, or reclaiming neglected or overgrown right of way. On the other hand, mechanical control methods can be non-selective and disturb sensitive sites.

Tree Growth Regulator and Herbicide Control Methods

Tree growth regulators and herbicides can be effective for vegetation management. Tree growth regulators (TGRs) are designed to reduce growth rates by interfering with natural plant processes. TGRs can be helpful where removals are prohibited or impractical by reducing the growth rates of some fast-growing species.

Herbicides control plants by interfering with specific botanical biochemical pathways. Herbicide use can control individual plants that are prone to re-sprout or sucker after removal. When trees that re-sprout or sucker are removed without herbicide treatment, dense thickets develop, impeding access, swelling workloads, increasing costs, blocking lines-of-site, and deteriorating wildlife habitat. Treating suckering plants allows early successional, compatible species to dominate the right-of-way and out-compete incompatible species, ultimately reducing work.

Cultural Control Methods

Cultural methods modify habitat to discourage incompatible vegetation and establish and manage desirable, early successional plant communities. Cultural methods take advantage of seed banks of native, compatible species lying dormant on site. In the long run, cultural control is the most desirable method where it is applicable.

A cultural control known as cover-type conversion provides a competitive advantage to short-growing, early successional plants, allowing them to thrive and eventually out-compete unwanted tree species for sunlight, essential elements and water. The early successional plant community is relatively stable, tree-resistant and reduces the amount of work, including herbicide application, with each successive treatment.

Wire-Border Zone

The wire-border zone technique is a management philosophy that can be applied through cultural control. W.C. Bramble and W.R. Byrnes developed it in the mid-1980s out of research begun in 1952 on a transmission right-of-way in the Pennsylvania State Game Lands 33 Research and Demonstration project (Yahner and Hutnik (2004).

The wire zone is the section of a utility transmission right-of-way directly under the wires and extending outward about 10 feet on each side. The wire zone is managed to promote a low-growing plant community dominated by grasses, herbs and small shrubs (under 3 feet in height at maturity). The border zone is the remainder of the right-of-way. It is managed to establish small trees and tall shrubs (under 25 feet in height at maturity). When properly managed, diverse, tree-resistant plant communities develop in wire and border zones. The communities not only protect the electric facility and reduce long-term maintenance, but also enhance wildlife habitat, forest ecology and aesthetic values.

Although the wire-border zone is a best practice in many instances, it is not necessarily universally suitable. For example, standard wire-border zone prescriptions may be unnecessary where lines are high off the ground, such as across low valleys or canyons, so the technique can be modified without sacrificing reliability.

One way to accommodate variances in topography is to establish different regions based on wire height. For example, over canyon bottoms or other areas where conductors are 100 feet or more above the ground, only a few trees are likely to be tall enough to conflict with the lines. In those cases, trees that potentially interfere with the transmission lines can be removed selectively on a case-by-case basis.

In areas where the wire is lower, perhaps between 50-100 feet from the ground, a border zone community can be developed throughout the right-of-way. Note that in many cases, conductor attachment points are more than 50 feet off the ground, so a border zone community can be cultivated near structures. Where the line is less than 50 feet off the ground, managers could apply a full wire-border zone prescription.

An environmental advantage of this type of modification is stream protection. Streams often course through the valleys and canyons where lines are likely to be elevated. Leaving timber or border zone communities in canyon bottoms helps shelter this valuable habitat, enabling managers to achieve environmentally sensitive objectives.

Implement IVM

All laws and regulations governing IVM practices and specifications written by qualified vegetation managers must be followed. Integrated vegetation management control methods should be implemented on regular work schedules, which are based on established objectives and completed assessments. Work should progress systematically, using control measures determined to be best for varying conditions at specific locations along a right-of-way. Some considerations used in developing schedules include the importance and type of line, vegetation clearances, work loads, growth rate of predominant vegetation, geography, accessibility, and in some cases, time lapsed since the last scheduled work.

Clearances Following Work

Clearances following work should be sufficient to meet management objectives, including preventing trees from entering the Minimum Vegetation Clearance Distance, electric safety risks, service-reliability threats and cost.

Monitor Treatment and Quality Assurance

An effective program includes documented processes to evaluate results. Evaluations can involve quality assurance while work is underway and after it is completed. Monitoring for quality assurance should begin early to correct any possible miscommunication or misunderstanding on the part of crewmembers. Early and consistent observation and evaluation also provides an opportunity to modify the plan, if need be, in time for a successful outcome.

Utility vegetation management programs should have systems and procedures in place for documenting and verifying that vegetation management work was completed to specifications. Post-control reviews can be comprehensive or based on a statistically representative sample. This final review points back to the first step and the planning process begins again.

Summary of A-300 example
Integrated Vegetation Management offers among others, a systematic way of planning and implementing a vegetation management program as presented in ANSI A300 Part 7. This methodology enables a program to comply with the NERC *Transmission Vegetation Management Program* standard (FAC-003-2). Managers should select control options to best promote management objectives.

Vegetation Inspections
As with the ANSI A-300 example, The Transmission Owner's transmission vegetation management program (TVMP) establishes the frequency of vegetation inspections based upon many factors. Such local and environmental factors may include anticipated growth rates of the local vegetation, length of the growing season for the geographical area, limited Rights of Way width, rainfall amounts, etc.

Annual Work Plan
Requirement R7 of the Standard addresses the execution of the annual work plan. A comprehensive approach that exercises the full extent of legal rights is superior to incremental management in the long term because it reduces overall encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient at all locations on the Right of Way. Removal is superior to pruning. Removal minimizes the possibility of conflicts between energized conductors and vegetation. Since this is not always possible, the Transmission Owner's approach should be to use its prescribed vegetation maintenance methods to work towards or achieve the maximum use of the Right of Way.

Requirement R4

R4. *Each Transmission Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable transmission line when the Transmission Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment.*

[VRF – Medium] [Time Horizon – Real-time]

Rationale
To ensure expeditious communication between the Transmission Owner and the control center when a critical situation is confirmed.

M4. *Each Transmission Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)*

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the Transmission Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of a Transmission Owner's employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The Transmission Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or positioning the system in recognition of the increasing risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some Transmission Owners may have a danger tree identification

program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5

R5. *When a Transmission Owner is constrained from performing vegetation work, and the constraint may lead to a vegetation encroachment into the MVCD of its applicable transmission lines prior to the implementation of the next annual work plan then the Transmission Owner shall take corrective action to ensure continued vegetation management to prevent encroachments. [VRF – Medium] [Time Horizon – Operations Planning]*

M5. *Each Transmission Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, and evidence that a line was de-energized. (R5)*

> **Rationale**
> Legal actions and other events may occur which result in constraints that prevent the Transmission Owner from performing planned vegetation maintenance work.
> In cases where the transmission line is put at potential risk due to constraints, the intent is for the Transmission Owner to put interim measures in place, rather than do nothing.
> The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the Transmission Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the Transmission Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the Transmission Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the Transmission Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the Transmission Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the Transmission Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for each location.
- In developing the specific action to mitigate the potential risk to the transmission line the Transmission Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The Transmission Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6

R6. *Each Transmission Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 months between inspections on the same ROW.*[3]

[VRF – Medium] [Time Horizon – Operations Planning]

M6. *Each Transmission Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable transmission lines at least once per calendar year but with no more than 18 months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)*

Rationale

Inspections are used by Transmission Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections that fits general industry practice. In addition, the fact that Vegetation Inspections can be performed in conjunction with general line inspections further facilitates a Transmission Owner's ability to meet this requirement. However, the Transmission Owner may determine that more frequent inspections are needed to maintain reliability levels, dependent upon such factors as anticipated growth rates of the local vegetation, length of the growing season for the geographical area, limited ROW width, and rainfall amounts. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The SDT added footnote 3 to address the situation where a Transmission Owner through no fault of its own, would be unable to complete the vegetation inspection within the allotted time period. This would include the situation of mutual aid as well as disasters to the Transmission Owner's own system.

The VSL for Requirement R6 has VSL categories ranked by the percentage of the required ROW inspections completed. To calculate the percentage of inspection completion, the Transmission Owner may choose units such as: line miles or kilometers, circuit miles or kilometers, pole line miles, ROW miles, etc.

[3] When the Transmission Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO is granted a time extension that is equivalent to the duration of the time the TO was prevented from performing the Vegetation Inspection.

For example, when a Transmission Owner operates 2,000 miles of 230 kV transmission lines this Transmission Owner will be responsible for inspecting all 2,000 miles of 230 kV transmission lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The “Low VSL” for R6 would apply in this example.

Requirement R7

Rationale

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. An annual vegetation work plan allows for work to be modified for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that the changes do not violate the encroachment within the MVCD.

R7. *Each Transmission Owner shall complete 100% of its annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not put the transmission system at risk of a vegetation encroachment) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include:*

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of a Transmission Owner[4]
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

  [VRF – Medium] [Time Horizon – Operations Planning]

M7. *Each Transmission Owner has evidence that it completed its annual vegetation work plan. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (including modifications if any), dated work orders, dated invoices, or dated inspection records. (R7)*

R7 is a risk-based requirement. The Transmission Owner is required to implement an annual work plan for vegetation management to accomplish the purpose of this Standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a “span-by-span”, or even a “line-by-line” detailed description of all work to be performed. It is only intended to require that the Transmission Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

[4] circumstances that are beyond the control of a Transmission Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, major storms as defined either by the TO or an applicable regulatory body, ice storms, and floods; arboricultural, horticultural or agricultural activities.

The ability to modify the work plan allows the Transmission Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance or work may be deferred to a subsequent year because of slower-than-expected growth. This situation may also include complying with mutual assistance agreements by moving resources off the Transmission Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan. Modifications to the annual work plan must always ensure the reliability of the electric Transmission system.

In general, the vegetation management maintenance approach should use the full extent of the Transmission Owner's legal rights on the ROW. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management in the long term because it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan, the Transmission Owner should allow time for reasonable and predictable procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases, the lead time for obtaining permits may necessitate preparing work plans more than a year prior to the start of work. Transmission Owners may also need to consider those special landowner requirements.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the Transmission Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs and walk-through reports.

Appendix 1: Clearance Distance Derivation by the Gallet Equation

The Gallet Equation is a well-known method of computing the required strike distance for proper insulation coordination, and has the ability to take into account various air gap geometries, as well as non-standard atmospheric conditions. When the Gallet Equation and conservative probabilistic methods are combined, i.e. deterministic design, sparkover probabilities of 10^{-6} or less are achieved. This approach is well known for its conservatism and was used to design the first 500 kV and 765 kV lines in North America [1]. Thus, the deterministic design approach using the Gallet Equation is used for the standard to compute the minimum strike distance between transmission lines and the vegetation that may be present in or along the transmission corridor.

Method Explanation (Gallet Equation)

In 1975 G. Gallet published a benchmark paper that provided a method to compute the critical flashover voltage (CFO) of various air gap geometries [4]. The Gallet Equation uses various "gap factors" to take into account various air gap geometries. Various gap factor values are provided in [1]. If the vegetation in a transmission corridor, e.g. a tree, is assumed electrically to be a large structure then the CFO of such an air gap geometry can be computed for dry or wet conditions using a well established equation proposed by Gallet [1],[2],[4],

$$CFO_A = k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\dfrac{8}{D}} \tag{1}$$

where,

k_w is defined as the factor that takes into account wet or dry conditions (dry = 1.0 and wet = 0.96) and phase arrangement (multiply by 1.08 for outside phase), e.g. outside phase and wet conditions = (0.96)(1.08) = 1.037,

k_g is defined as the gap factor (1.3 for conductor to large structure),

D is the strike distance (m),

CFO_A is the CFO for the relative air density (kV).

δ is defined as the relative air density and is approximately equal to (2) where A is the altitude in km,

$$\delta = e^{-\frac{A}{8.6}} \tag{2}$$

$$m = 1.25G_0\left(G_0 - 0.2\right) \tag{3}$$

$$G_0 = \frac{CFO_s}{500 \cdot D} \tag{4}$$

$$CFO_s = k_w \cdot k_g \cdot \frac{3400}{1+\frac{8}{D}} \tag{5}$$

where CFO_S is the CFO for standard atmospheric conditions (kV). Using (1)-(5), the required CFO_A can be computed using an iterative process.

Once the CFO_A is known, deterministic methods can be used to determine the required clearance distance. If we let the maximum switching overvoltage be equal to the withstand voltage of the air gap (CFO_A - 3σ) then the CFO_A can be written as (6).

$$CFO_A = \frac{V_m}{1-3\left(\frac{\sigma}{CFO_A}\right)} \tag{6}$$

where

V_m is equal to the maximum switching overvoltage, i.e. the value that has a 0.135% chance of being exceeded,

σ is the standard deviation of the air gap insulation,

CFO_A is the critical flashover voltage of the air gap insulation under non-standard atmospheric conditions.

The ratio of σ to the CFO_A given in (6) can be assumed to be 0.05 (5%) [1]. Thus, (6) can be written as (7).

$$CFO_A = \frac{V_m}{0.85} \tag{7}$$

Substituting (7) into (1) we arrive at (8).

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} \tag{8}$$

Equation 8 relates the maximum transient overvoltage, V_m, to the air gap distance, D. Using (8) to compute the required clearance distance for the specified air gap geometry (conductor to large structure) results in a probability of flashover in the range of 10^{-6}.

Transient Overvoltage

In general, the worst case transient overvoltages occurring on a transmission line are caused by energizing or re-energizing the line with the latter being the extreme case if trapped charge is present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to sparkover from the line conductor to nearby vegetation. Thus, the worst case scenarios that are typically analyzed for insulation coordination purposes (e.g. line energization and re-energization) can be ignored. For the purposes of FAC-003-2, the worst case transient overvoltage then becomes the maximum value that can occur with the line energized. Determining a realistic value of transient overvoltage for this situation is difficult because the maximum transient overvoltage factors listed in the literature are based on a

switching operation of the line in question. In other words, these maximum overvoltage values (e.g. the values listed in [2], [3] and [5]) are based on the assumption that the subject line is being energized, re-energized or de-energized. These operations, by their very nature, will create the largest transient overvoltages. Typical values of transient overvoltages of in-service lines, as such, are not readily available in the literature because the resulting level of overvoltage is negligible compared with the maximum (e.g. re-energizing a transmission line with trapped charge). A conservative value for the maximum transient overvoltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 p.u.[2]. This value is a conservative estimate of the transient overvoltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without a pre-insertion device (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. 362 kV), the maximum transient overvoltage of an “in-service” ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 p.u. or less [2]. It is well known that these theoretical transient overvoltages will not be experienced at locations remote from the bus at which they were created; however, in order to be conservative, it will be assumed that all nearby ac lines are subjected to this same level of overvoltage. Thus, a maximum transient overvoltage factor of 2.0 p.u. for 242 kV and below and 1.4 p.u. for ac transmission lines 362 kV and above is used to compute the required clearance distances for vegetation management purposes.

The overvoltage characteristics of dc transmission lines vary somewhat from their ac counterparts. The referenced empirically derived transient overvoltage factor used to calculate the minimum clearance distances from dc transmission lines to vegetation for the purpose of FAC-003-2 will be 1.8 p.u.[3].

Example Calculation

An example calculation is presented below using the proposed method of computing the vegetation clearance distances. It is assumed that the line in question has a maximum operating voltage of 550 kV_{rms} line-to-line. Using a per unit transient overvoltage factor of 1.4, the result is a peak transient voltage of 629 kV_{crest}. It is further assumed that the line in question operates at a maximum altitude of 7000 feet (2.134 km) above sea level.

The required withstand voltage of the air gap must be equal to or greater than 629 kV_{crest}. Since the altitude is above sea level, (1) - (5) have to be iterated on to achieve the desired result. Equation (9) can be used as an initial guess for the clearance distance.

$$D_i = \frac{8}{\dfrac{3400 \cdot k_w \cdot k_g}{\left(\dfrac{V_m}{0.85}\right)} - 1} \tag{9}$$

For our case here, V_m is equal to 629 kV, k_w = 1.037 and k_g = 1.3. Thus,

$$D_i = \frac{8}{\dfrac{3400 \cdot k_w \cdot k_g}{\left(\dfrac{V_m}{0.85}\right)} - 1} = \frac{8}{\dfrac{3400 \cdot 1.037 \cdot 1.3}{\left(\dfrac{629}{0.85}\right)} - 1} = 1.535m \tag{10}$$

Using (2)-(5) and (8) the withstand voltage of the air gap is next computed. This value will then be compared to the maximum transient overvoltage.

$$CFO_S = k_w \cdot k_g \cdot \frac{3400}{1+\frac{8}{D}} = 1.037 \cdot 1.3 \cdot \frac{3400}{1+\frac{8}{1.535}} = 737.7kV \tag{11}$$

$$\delta = e^{-\frac{A}{8.6}} = e^{-\frac{2.134}{8.6}} = 0.78 \tag{12}$$

$$G_O = \frac{CFO_S}{500 \cdot D} = \frac{737.7}{(500)\cdot(1.535)} = 0.961 \tag{13}$$

$$m = 1.25 \cdot G_O(G_O - 0.2) = 1.25 \cdot 0.961(0.961 - 0.2) = 0.915 \tag{14}$$

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} = (0.85)(1.037)(1.3)(0.78)^{0.915}\left(\frac{3400}{1+\frac{8}{1.535}}\right) = 499.8kV \tag{15}$$

The calculated V_m is less than 629 kV; thus, the clearance distance must be increased. A few iterations using (2)-(5) and (8) are required until the computed $V_m \geq 629$ kV. For this case it was found that D = 1.978 m (6.49 feet) yielded V_m = 629.3 kV. Using this clearance distance the following values were computed for the final iteration.

$$CFO_S = k_w \cdot k_g \cdot \frac{3400}{1+\frac{8}{D}} = 1.037 \cdot 1.3 \cdot \frac{3400}{1+\frac{8}{1.978}} = 908.5kV \tag{16}$$

$$\delta = e^{-\frac{A}{8.6}} = e^{-\frac{2.134}{8.6}} = 0.78 \tag{17}$$

$$G_O = \frac{CFO_S}{500 \cdot D} = \frac{908.5}{(500)\cdot(1.978)} = 0.919 \tag{18}$$

$$m = 1.25 \cdot G_O(G_O - 0.2) = 1.25 \cdot 0.919(0.919 - 0.2) = 0.825 \tag{19}$$

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} = (0.85)(1.037)(1.3)(0.78)^{0.825}\left(\frac{3400}{1+\frac{8}{1.978}}\right) = 629.3kV \tag{20}$$

Therefore, the minimum vegetation clearance distance for a maximum line to line ac operating voltage of 550 kV at 7000 feet above sea level is 1.978 m (6.49 feet). Table 1 provides calculated distances for various altitudes and maximum system operating ac voltages.

TABLE 1 — Minimum Vegetation Clearance Distances (MVCD)[6]
For **Alternating Current** Voltages

(AC) Nominal System Voltage (kV)	(AC) Maximum System Voltage (kV)	MVCD feet (meters) sea level	MVCD feet (meters) 3,000ft (914.4m)	MVCD feet (meters) 4,000ft (1219.2m)	MVCD feet (meters) 5,000ft (1524m)	MVCD feet (meters) 6,000ft (1828.8m)	MVCD feet (meters) 7,000ft (2133.6m)	MVCD feet (meters) 8,000ft (2438.4m)	MVCD feet (meters) 9,000ft (2743.2m)	MVCD feet (meters) 10,000ft (3048m)	MVCD feet (meters) 11,000ft (3352.8m)
765	800	8.06ft (2.46m)	8.89ft (2.71m)	9.17ft (2.80m)	9.45ft (2.88m)	9.73ft (2.97m)	10.01ft (3.05m)	10.29ft (3.14m)	10.57ft (3.22m)	10.85ft (3.31m)	11.13ft (3.39m)
500	550	5.06ft (1.54m)	5.66ft (1.73m)	5.86ft (1.79m)	6.07ft (1.85m)	6.28ft (1.91m)	6.49ft (1.98m)	6.7ft (2.04m)	6.92ft (2.11m)	7.13ft (2.17m)	7.35ft (2.24m)
345	362	3.12ft (0.95m)	3.53ft (1.08m)	3.67ft (1.12m)	3.82ft (1.16m)	3.97ft (1.21m)	4.12ft (1.26m)	4.27ft (1.30m)	4.43ft (1.35m)	4.58ft (1.40m)	4.74ft (1.44m)
230	242	2.97ft (0.91m)	3.36ft (1.02m)	3.49ft (1.06m)	3.63ft (1.11m)	3.78ft (1.15m)	3.92ft (1.19m)	4.07ft (1.24m)	4.22ft (1.29m)	4.37ft (1.33m)	4.53ft (1.38m)
161*	169	2ft (0.61m)	2.28ft (0.69m)	2.38ft (0.73m)	2.48ft (0.76m)	2.58ft (0.79m)	2.69ft (0.82m)	2.8ft (0.85m)	2.91ft (0.89m)	3.03ft (0.92m)	3.14ft (0.96m)
138*	145	1.7ft (0.52m)	1.94ft (0.59m)	2.03ft (0.62m)	2.12ft (0.65m)	2.21ft (0.67m)	2.3ft (0.70m)	2.4ft (0.73m)	2.49ft (0.76m)	2.59ft (0.79m)	2.7ft (0.82m)
115*	121	1.41ft (0.43m)	1.61ft (0.49m)	1.68ft (0.51m)	1.75ft (0.53m)	1.83ft (0.56m)	1.91ft (0.58m)	1.99ft (0.61m)	2.07ft (0.63m)	2.16ft (0.66m)	2.25ft (0.69m)
88*	100	1.15ft (0.35m)	1.32ft (0.40m)	1.38ft (0.42m)	1.44ft (0.44m)	1.5ft (0.46m)	1.57ft (0.48m)	1.64ft (0.50m)	1.71ft (0.52m)	1.78ft (0.54m)	1.86ft (0.57m)
69*	72	0.82ft (0.25m)	0.94ft (0.29m)	0.99ft (0.30m)	1.03ft (0.31m)	1.08ft (0.33m)	1.13ft (0.34m)	1.18ft (0.36m)	1.23ft (0.37m)	1.28ft (0.39m)	1.34ft (0.41m)

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above).

[6] The distances in this Table are the minimums required to prevent Flashover; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

TABLE 1 (CONT.) — Minimum Vegetation Clearance Distances (MVCD)
For **Direct Current** Voltages

(DC) Nominal Pole to Ground Voltage (kV)	**MVCD feet (meters) sea level**	**MVCD feet (meters) 3,000ft (914.4m) Alt.**	**MVCD feet (meters) 4,000ft (1219.2m) Alt.**	**MVCD feet (meters) 5,000ft (1524m) Alt.**	**MVCD feet (meters) 6,000ft (1828.8m) Alt.**	**MVCD feet (meters) 7,000ft (2133.6m) Alt.**	**MVCD feet (meters) (8,000ft (2438.4m) Alt.**	**MVCD feet (meters) 9,000ft (2743.2m) Alt.**	**MVCD feet (meters) 10,000ft (3048m) Alt.**	**MVCD feet (meters) 11,000ft (3352.8m) Alt.**
±750	13.92ft (4.24m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.9ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.07ft (3.07m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	(13.54ft 4.13m)
±500	7.89ft (2.40m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	4.78ft (1.46m)	5.35ft (1.63m)	5.55ft (1.69m)	5.75ft (1.75m)	5.95ft (1.81m)	6.15ft (1.87m)	6.36ft (1.94m)	6.57ft (2.00m)	6.77ft (2.06m)	6.98ft (2.13m)
±250	3.43ft (1.05m)	4.02ft (1.23m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5ft (1.52m)	5.17ft (1.58m)

List of Acronyms and Abbreviations

ANSI	American National Standards Institute
IEEE	Institute of Electrical and Electronics Engineers
IVM	Integrated Vegetation Management
NERC	North American Electric Reliability Corporation

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Transmission Vegetation Management
Standard FAC-003-2 Technical Reference

Prepared by the

North American Electric Reliability Corporation

Vegetation Management Standard Drafting Team

~~June 28~~December 17, 2010

~~Table of Contents~~

Introduction

This document is intended to provide supplemental information and guidance for complying with the requirements of Reliability Standard FAC-003-2.

The purpose of the Standard is to improve the reliability of the electric transmission system by preventing those vegetation related outages that could lead to Cascading.

Compliance with the Standard is mandatory and enforceable.

Special Note: The Application of Results-Based Approach to FAC-003-2

In its three-year assessment as the ERO, NERC acknowledged stakeholder comments and committed to:

i) addressing quality issues to ensure each reliability standard has a clear statement of purpose, and has outcome-focused requirements that are clear and measurable; and
ii) eliminating requirements that do not have an impact on bulk power system reliability.

In 2010, the Standards Committee approved a recommendation to use Project 2007-07 Vegetation Management as a first proof of concept for developing results-based standards.

The Standard Drafting Team (SDT) employed a defense-in-depth[1] strategy for FAC-003-2, where each requirement has a role in preventing those vegetation related outages that could lead to Cascading. This portfolio of requirements was designed to achieve an overall defense-in-depth strategy and to comply with the quality objectives identified in the *Acceptance Criteria of a Reliability Standard* document.

The SDT developed a portfolio of performance, risk, and competency-based mandatory reliability requirements to support an effective defense-in-depth strategy. Each Requirement was developed using one of the following requirement types:

a) Performance-based - defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?
b) Risk-based - preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?
c) Competency-based - defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

The drafting team reviewed and edited version 1 of FAC-003-1 to remove prescriptive and administrative language in order to distill the technical requirements down to their

[1] A defense-in-depth strategy for reliability standards recognizes that each requirement in the NERC standards has a role in preventing system failures, and that these roles are complementary and reinforcing. These prevention measures should be arranged in a series of defensive layers or walls. No single defensive layer provides complete protection from failure by itself. But taken together, with well-designed layers including performance, risk, and competency-based requirements, a defense-in-depth approach can be very effective in preventing future large scale power system failures.

essential reliability content. Text that is explanatory in nature is placed in a special section of the standard entitled Guideline and Technical Basis to aid in the understanding of the requirements. Furthermore, Rationale text boxes are inserted alongside each requirement to communicate the foundation for the requirement.

Disclaimer

This supporting document is supplemental to the reliability standard FAC-003-2 — Transmission Vegetation Management and does not contain mandatory requirements subject to compliance review.

Preface

The NERC Vegetation Management Standard Drafting Team (VM SDT) acknowledges those across the industry who contributed to the development of this Standard and companion Technical Reference document. The Technical Reference document is intended to provide supplemental explanatory background and guidance related to requirements contained in the Standard but does not in itself contain requirements subject to compliance review.

The VM SDT believes that a well-designed and executed Transmission Vegetation Management Program (TVMP) will have few problems meeting the requirements of this Standard. While the Standard requires a TVMP to contain certain elements, it allows the Transmission Owner flexibility in designing a TVMP to meet local needs provided it also meets the purpose of the Standard.

While there are many approaches to vegetation management, the VMSDT supports industry best practices contained in ANSI A300 (Part 7) – Integrated Vegetation Management (IVM) practices on Utility Rights-of-way, as well as the companion publication Best Management Practices – Integrated Vegetation Management, as an effective strategy to maintain compliance with this Standard. ANSI A300 (Part 7), approved by industry consensus in 2006, contains many elements needed for an effective TVMP as required by this Standard. One key element is the "wire zone – border zone" concept. Supported by over 50 years of continuous research, wire zone – border zone is a proven method to manage vegetation on transmission rights-of-ways and is an industry accepted best practice to help ensure electric system reliability.

The VM SDT believes that Transmission Owners who adopt and effectively implement IVM principles, particularly the "wire zone – border zone" concept, are far less likely to experience a vegetation caused outage than those who do not.

Definition of Terms

Right-of-Way (ROW)*

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.

The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

The current NERC glossary definition of Right of Way has been modified to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of "right of way" in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis.

Vegetation Inspection~~ —~~ ***

The systematic examination of vegetation conditions on ~~an Active Transmission Line Right-of-Way which~~a Right-of-Way and those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.

Current definition of Vegetation Inspection: The systematic examination of a transmission corridor to document vegetation conditions.

The inspection includes the identification of any vegetation that may pose a threat to reliability prior to the next planned ~~inspection or~~ maintenance or inspection work, considering the current location of the conductor and other possible locations of the conductor due to sag and sway for rated conditions.

This definition allows both maintenance inspections and vegetation inspections to be performed concurrently.

~~*To~~

* This is a modification to a defined term in the NERC glossary and will be ~~added to~~incorporated into the NERC glossary of terms with final approval of this standard revision
~~** This is a modification to a defined term in the NERC glossary.~~

Applicability of the Standard

4. Applicability

4.1. Functional Entities:
Transmission Owners

4.2. Facilities: *Defined below~~,~~ (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal*[1]*, state, provincial, public, private, or tribal entities:*

4.2.1 *Overhead transmission lines operated at 200kV or higher.*
4.2.2 *Overhead transmission lines operated below 200kV having been identified as included in the definition of an Interconnection Reliability Operating Limit (IROL) under NERC Standard FAC 014 by the Planning Coordinator.*
4.2.3 *Overhead transmission lines operated below 200 kV having been identified as included in the definition of one of the Major WECC Transfer Paths in the Bulk Electric System.*
4.2.4 *This standard ~~does not apply~~applies to ~~Facilities~~overhead transmission lines identified above (4.2.1 through 4.2.3) located ~~in~~outside the fenced area of ~~a~~the switchyard, station or substation~~.~~ and any portion of the span of the transmission line that is crossing the substation fence.*

4.3. Enforcement: *The reliability obligations of the applicable entities and facilities are contained within the technical requirements of this standard. [Straw proposal]*

Rationale
-The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) The standard was written for Transmission Owners. Rolling the excluded areas into this standard will bring GO and DP into the standard, even though NERC has an initiative in place to address this bigger registry issue. 4) Specifically addressing the areas where the standard applies or doesn't makes the standard stronger as it relates to clarity.

~~***4.4. Other:***~~
~~*This Standard does not apply to any occurrence, non-occurrence, or other set of circumstances that are beyond the control of a Transmission Owner subject to this reliability standard, including acts of God, flood, drought, earthquake, major storms, fire, hurricane, tornado, landslides, ice storms, vehicle contact with tree, human activity involving: removal of, installation of, or digging around vegetation, animals severing trees, lightning, epidemic, strike, war, riot, civil disturbance, sabotage, vandalism, terrorism, wind shear, or fresh gale (or higher wind speed) that restricts or prevents performance to comply with this reliability standard's*~~

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies"*.

~~*requirements. Nothing in this section should be construed to limit the Transmission Owner's right to exercise its full legal rights on the Active Transmission Line ROW.*~~

In Order 693, FERC discussed the 200 kV bright-line test of applicability. While FERC did not change the 200 kV bright ~~-~~line, the Commission remained concerned that there may be some transmission lines operating at lesser voltages that could have significant impact on the Bulk Electric System that should therefore be subject to this standard.

NERC Standard FAC-014 has the stated purpose, "*To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.*" FAC-014 requires Reliability Coordinators, Planning Coordinators, and Transmission Planners to have a methodology to identify all lines that might comprise an IROL. Thus, these entities would identify sub-200 kV lines that qualify as part of an IROL and should be subject to FAC-003-2.

Although all three entities may prepare the list of elements, FAC-003-2 presently does not specify that it is the list from the Planning Coordinator that should be used by Transmission Owners for FAC-003. However, the Time Horizon needed to plan vegetation management work does not lend itself to the operating horizon of a Reliability Coordinator. Additionally, the Planning Coordinator has a wider-area view than the Transmission Planner and could thus identify any elements of importance to a sub-set of its area that might be missed by a Transmission Planner.

Transmission Owners, who do not already get the list of circuits included in the definition of an IROL, can get them from the Planning Coordinator. Specifically R5 of FAC-014 specifies that "*The Reliability Coordinator, Planning Authority (Coordinator) and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits*"

Vegetation-related Sustained Outages that occur due to natural disasters are beyond the control of the Transmission Owner. These events are not classified as vegetation-related Sustained Outages and are therefore exempt from the Standard. Transmission lines are not designed to withstand the impacts of natural disasters such as flood, drought, earthquake, major storms, fire, hurricane, tornado, landslides, ice storms, etc. In the aftermath of catastrophic system damage from natural disasters the Transmission Owner's focus is on electric system restoration for public safety and critical support infrastructure.

Sustained Outages due to human or animal activity are beyond the control of the Transmission Owner. These outages are not classified as vegetation-related Sustained Outages and are therefore exempt from the Standard. Examples of these events may include new plantings by outside parties of tall vegetation under the transmission line planted since the last Vegetation Inspection, tree contacts with line initiated by vehicles, logging activities, etc.

The foregoing exemptions are addressed in a new ~~subsection, 4.4 Other, of the Applicability section.~~footnote 2. Referred to collectively as force majeure events and activities, this ~~section~~footnote applies to ~~all~~ requirements R1 and R2 in FAC-003-2.

The reliability objective of this NERC Vegetation Management Standard ("Standard") is to prevent vegetation-related outages which could lead to Cascading by effective vegetation maintenance while recognizing that certain outages such as those due to vandalism, human errors and acts of nature are not preventable. Operating experience clearly indicates that trees that have grown out of specification could contribute to a cascading grid failure, especially under heavy electrical loading conditions.

Serious outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. To properly reduce and manage this risk, it is necessary to apply the Standard to applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee. For the purposes of the Standard and this Technical Reference document, the term “public lands” includes municipal lands, village lands, city lands, and land owned by a host of other governmental entities.

The Standard addresses vegetation management along applicable overhead lines that serve to connect one electric station to another. However, it is not intended to be applied to lines sections inside the electric station fence or other boundary of an electric station, submarine or underground lines.

The Standard is intended to reduce the risk of Cascading involving vegetation. It is not intended to prevent customer outages from occurring due to tree contact with all transmission lines and voltages. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this Standard is not written to address such isolated situations which have little impact on the overall Bulk Electric System.

Vegetation growth is constant and always present. Unmanaged vegetation poses an increased outage risk when numerous transmission lines are operating at or near their Rating. This poses a significant risk of multiple line failures and Cascading. On the other hand, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are statistically intermittent. The probability of occurrence of these events is not dependent on heavy loads. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures.

In preparing the original vegetation management standard in 2005, industry stakeholders set the threshold for applicability of the standard at 200kV. This was because an unexpected loss of lines operating at above 200kV has a higher probability of initiating a widespread blackout or cascading outages compared with lines operating at less than 200kV.

The original NERC Standard FAC-003-1 also allowed for application of the standard to “critical” circuits (critical from the perspective of initiating widespread blackouts or cascading outages) operating below 200kV. While the percentage of these circuits is relatively low, it remains a fact that there are sub-200kV circuits whose loss could contribute to a widespread outage. Given the very limited exposure and unlikelihood of a major event related to these lower-voltage lines, it would be an imprudent use of resources to apply the Standard to all sub-200kV lines. The drafting team, after evaluating several alternatives, selected the IROL and WECC Major Transfer Path criteria to determine applicable lines below 200 kV that are subject to this standard.

~~*Active Transmission Line ROW*~~

~~The term "Active Transmission Line Right of Way" is defined in the Standard in a footnote repeated for convenience below:~~

> ~~*A strip or corridor of land that is occupied by active transmission facilities. This corridor does not include the parts of the Right-of-Way that are unused or intended for other facilities. However, it is not to be less than the width of the easement itself unless the easement exceeds distances as shown in Table 3 for various voltage classes.*~~

~~The term Right of Way (ROW) can be used in reference to many situations. This is partially because some lines are built on the land that is owned fee simple by the transmission owner, other lines are built across federal or provincial lands with only limited rights under a permit or agreement, and many other lines cross lands with only limited easement rights to construct, operate and maintain the line. Transmission line configurations on ROWs are present in many combinations of multiple circuits on various tower types. The number of circuits and configurations change along the length of the ROW due to circuits departing to other locations or terminating at nearby substations. Figures 1, 2 and 3 on the following pages depict several typical transmission line configurations on typical rights of way.~~

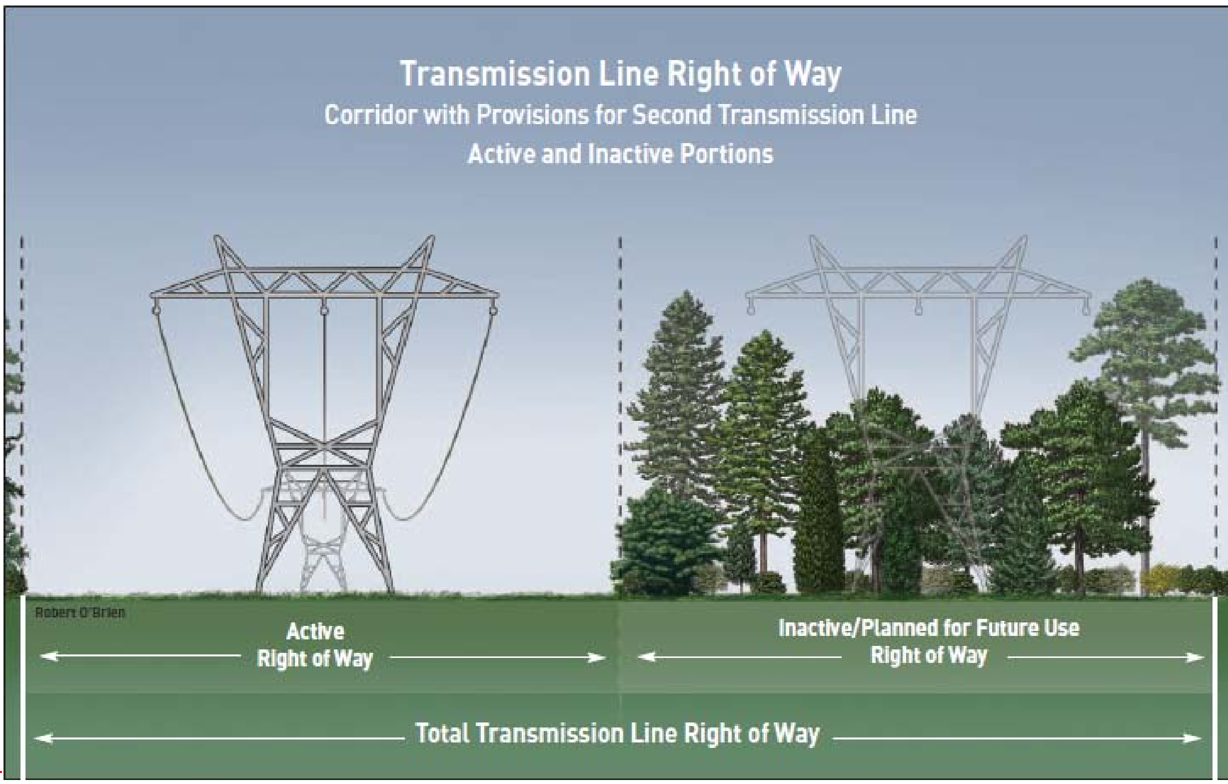
~~A Transmission Owner may plan for a nominal width along the entire length of a line during planning using its design specifications for a particular circuit configuration and voltage. The actual acquired ROW width at the time a circuit is constructed is however impacted in many cases, by other considerations. Those considerations include other future circuits that may be built adjacent to the subject line, or property parcels with unusual 'extra" widths due to special property owner demands during initial acquisition, or other existing lines adjacent to the subject line (which may be retired or abandoned at a future date). Refer to Figures 1 and 3 for common examples of such situations.~~

~~This Standard requires the Transmission Owner to prevent sustained outages due to vegetation "growing into" or "blowing together" with line conductors if that vegetation is under the line or growing beside the line (provided the Transmission Owner has the legal right to remove or trim the vegetation growing beside the line). Transmission Owners are also required to prevent sustained outages due to fall-ins from trees that, before falling, were standing inside the limits established in footnote 2 and associated "Table 3" (see below).~~

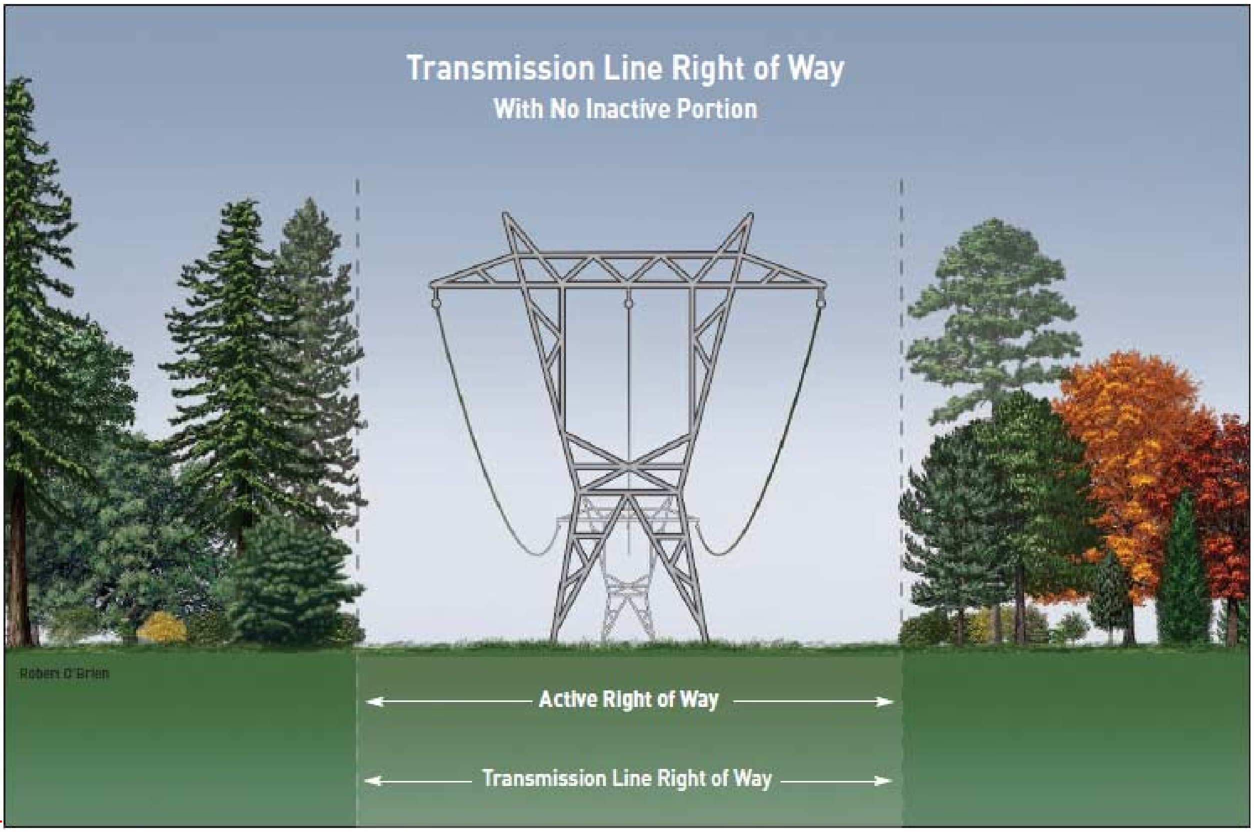
~~However it is recognized that any requirement in this standard to impose violations for sustained outages due to "fall-ins" must consider the impact of forcing the clearing of ROWs to the legal edge or to widths wider than they are typically managed. Therefore the standard drafting team inserted the subject footnote "active transmission line ROW" to provide a distance for a Transmission Owner to use if they do not already have a codified ROW width for a particular circuit or voltage". This approach of defining "active" and "inactive" right of way is intended to clarify the confusion created by the current standard which simply states that a fall-in from within the ROW is a violation. This provides the Transmission Owner with a means to define a right of way width that is applicable to fall-ins, provided it is not less than those limits in "Table 3".~~

~~69 - 138 kV~~	~~37.5 ft.~~
~~139 - 230 kV~~	~~50 ft.~~
~~231 - 345 kV~~	~~75 ft.~~
~~346 - 500 kV~~	~~87.5 ft.~~
~~501 - 765 kV~~	~~100 ft.~~

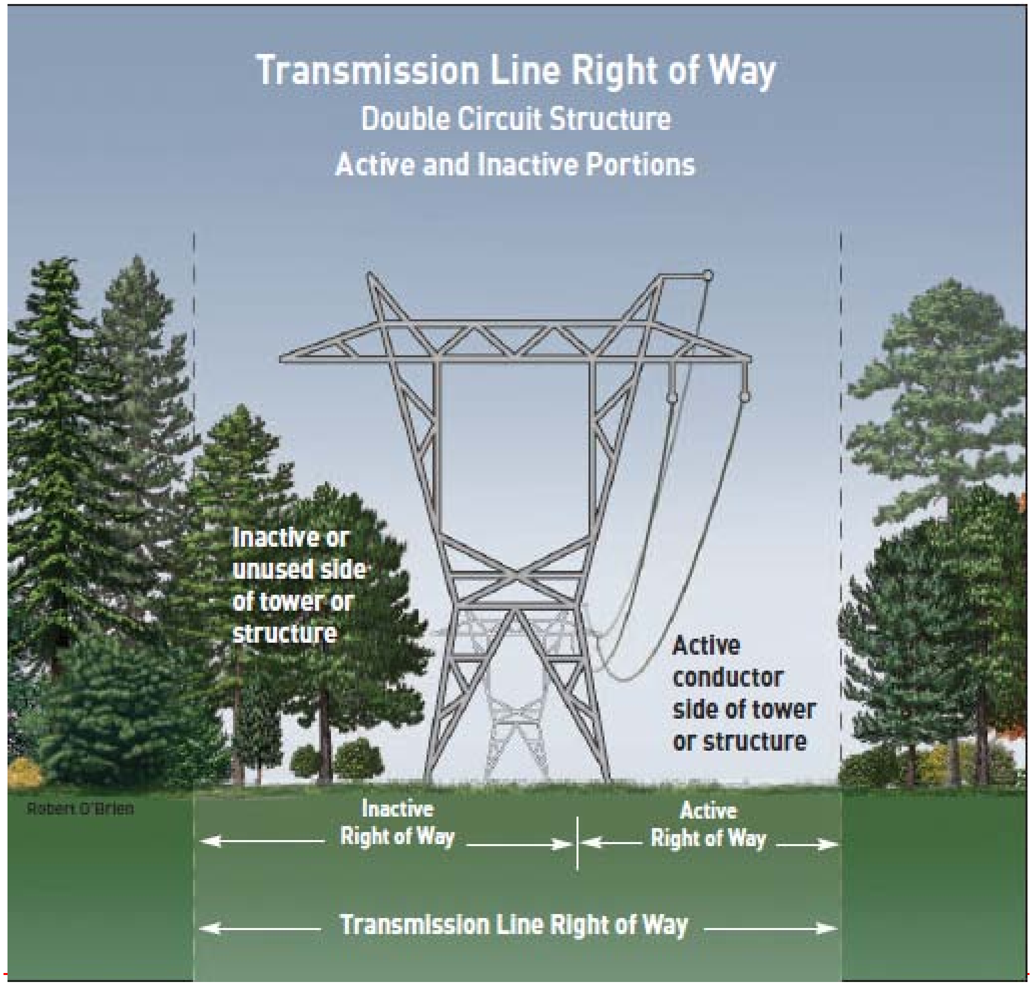
~~"Table 3 – Minimum Distance from the Centerline of the Circuit to the edge of the active transmission line ROW"~~



~~Figure 1~~


Transmission Line Right of Way
With No Inactive Portion
Robert O'Brien
Active Right of Way
Transmission Line Right of Way

~~Figure 2~~


Transmission Line Right of Way
Double Circuit Structure
Active and Inactive Portions
Inactive or unused side of tower or structure
Active conductor side of tower or structure
Robert O'Brien
Inactive Right of Way
Active Right of Way
Transmission Line Right of Way

~~Figure 3~~

Requirements R1 and R2

R1. *Each Transmission Owner shall manage vegetation to prevent ~~encroachment that could result in a Sustained Outage of any line~~encroachments of the types shown below, into the Minimum Vegetation Clearance Distance (MVCD) of any of its applicable line(s) identified as an element of an Interconnection Reliability Operating Limit (IROL) in the planning horizon by the Planning Coordinator; or Major Western Electricity Coordinating Council (WECC) transfer path ~~(~~(s); operating within its Rating and all Rated Electrical Operating Conditions~~). Types of encroachment include:~~.[2]*

1. *An encroachment into the ~~Minimum Vegetation Clearance Distance (MVCD)~~ MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,*
2. *An encroachment due to a fall-in from inside the ~~Active Transmission Line ROW~~Right-of-Way (ROW) that caused a vegetation-related Sustained Outage,*
3. *An encroachment due to blowing together of applicable lines and vegetation located inside the ~~Active Transmission Line~~ ROW that caused a vegetation-related Sustained Outage,*
4. *An encroachment due to a grow-in that caused a vegetation-related Sustained Outage.*
   [VRF – High] [Time Horizon – Real-time]

~~Rationale~~

~~The MVCD is a calculated minimum distance stated in feet (meters) to prevent spark-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method.~~

e 2

manage vegetation are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO's vegetation maintenance program since the encroachments listed require different and increasing levels of skills and knowledge and thus constitute a logical progression of how well, or poorly, a TO manages vegetation relative to this Requirement.

[2] This requirement does not apply to circumstances that are beyond the control of a Transmission Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

R2. *Each Transmission Owner shall manage vegetation to prevent ~~**encroachment that could result in a Sustained Outage**~~encroachments of the types shown below, into the MVCD of any of its applicable ~~**lines**~~line(s) that ~~**are**~~is not ~~**elements of**~~ an ~~**Interconnection Reliability Operating Limit (**~~element of an IROL~~)~~; or Major ~~**Western Electricity Coordinating Council (**~~WECC~~)~~ transfer path ~~(~~; operating within its Rating and all Rated Electrical Operating Conditions~~). Types of encroachment include:~~.*Error! Bookmark not defined.

1. *An encroachment into the ~~Minimum Vegetation Clearance Distance (MVCD)~~MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage,*
2. *An encroachment due to a fall-in from inside the ~~Active Transmission Line~~ ROW that caused a vegetation-related Sustained Outage,*
3. *An encroachment due to blowing together of applicable lines and vegetation located inside the ~~Active Transmission Line~~ ROW that caused a vegetation-related Sustained Outage,*
4. *An encroachment due to a grow-in that caused a vegetation-related Sustained Outage. [VRF – Medium] [Time Horizon – Real-time]*

M1. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, ~~*reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-Time observations of any MVCD encroachments.*~~

dated~~Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.~~ ~~*If an investigation of a Fault by a qualified person confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered a Real-time observation.*~~

~~***M2.*** *Each Transmission Owner has evidence that it managed vegetation as described in R2. Examples of acceptable forms of evidence may include attestations,*~~ reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments.

If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. (R1)

M2. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained

Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments.

If ~~*an investigation*~~a later confirmation of a Fault by ~~*a qualified person confirms*~~the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred~~*, then it*~~ from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. (R2)

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the prevention of vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each Transmission Owner to ~~prevent~~manage vegetation ~~from encroaching~~to prevent encroachment within the Minimum Vegetation Clearance Distance ("MVCD") of transmission lines. R1 is applicable to lines "identified as an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions) to avoid a Sustained Outage". R2 applies to all other applicable lines that are not an element of an IROL or Major WECC Transfer Path.

The separation of applicability (between R1 and R2) recognizes that an encroachment into the MVCD of an IROL or Major WECC Transfer Path transmission line is a greater risk to the electric transmission system. Applicable lines that are not an element of an IROL or Major WECC Transfer Path are required to be clear of vegetation but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

These requirements (R1 and R2) state that if vegetation encroaches within the distances in Table 1 in Appendix 1 of this supplemental Transmission Vegetation Management Standard FAC-003-2 Technical Reference document, it is in violation of the standard. Table ~~1~~2 tabulates the distances necessary to prevent spark-over based on the Gallet equations as described more fully in Appendix 1 below.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating (potentially in violation of other standards), the occurrence of a clearance encroachment may occur. For example, emergency actions taken by a Transmission Operator or Reliability Coordinator to protect an Interconnection may cause the transmission line to sag more and come closer to vegetation, potentially causing an outage. Such vegetation-related outages are not a violation of these requirements.

Evidence of violation of Requirement R1 and R2 include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ~~Active Transmission Line~~ ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to blowing together of applicable lines and vegetation located inside the ~~Active Transmission Line~~ ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. If an investigation of a Fault by a ~~qualified person~~Transmission Owner confirms that a vegetation encroachment within the MVCD occurred, then it shall be considered the equivalent of a Real-time observation.

With this approach, the VSLs were defined such that they directly correlate to the severity of a failure of a Transmission Owner to ~~keep~~manage vegetation~~ away from conductors~~ and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the goal of "preventing a Sustained Outage that could lead to Cascading." Thus violation severity increases with a Transmission Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation~~,~~. For example, a limb ~~that~~may only partially ~~breaks~~break and intermittently ~~contacts~~contact a conductor. Such events are considered to be a single vegetation-related Sustained Outage under the Standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will ~~help~~ prevent transmission outages.

Requirement R3

> **Rationale**
> ~~Provide~~The documentation provides a basis for ~~evaluation on~~evaluating the ~~intent and~~ competency of the Transmission ~~Owner in maintaining~~Owner's vegetation program. There may be many acceptable approaches to maintain clearances. ~~However,~~Any approach must demonstrate that the Transmission Owner ~~should be able~~ avoids vegetation-to ~~state what its approach is and how it conducts work to maintain clearances.~~-wire conflicts under all Rated Electrical Operating Conditions. See Figure 1 *~~[in Standard FAC-003-2]~~* for an illustration of possible conductor locations.

R3. *Each Transmission Owner shall ~~document the~~ have documented maintenance strategies or procedures~~,~~ or processes~~,~~ or specifications it uses to prevent the encroachment of vegetation into the MVCD~~. Such documentation will incorporate~~ of its applicable transmission lines that include(s) the following:*

3.1 Accounts for the ~~dynamics~~movement of ~~a~~applicable transmission line ~~conductor's movement throughout its~~ conductors under their Facility Rating and all Rated Electrical Operating Conditions ~~and~~;

3.2 Accounts for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency~~, for the Transmission Owner's applicable lines~~.

[VRF – Lower] [Time Horizon – Long Term Planning]

M3. *The maintenance strategies or procedures~~,~~ or processes~~,~~ or specifications provided demonstrate that the Transmission Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)*

Requirement R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, a Transmission Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the Transmission Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the Transmission System. The approach provides the basis for evaluating the intent, allocation of appropriate resources and the competency of the Transmission Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the Transmission Owner must be able to state what its approach is and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach a Transmission Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the Transmission Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing as a reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in ~~Figure 5~~Figures 2 and 3 below.

Conductor Dynamics

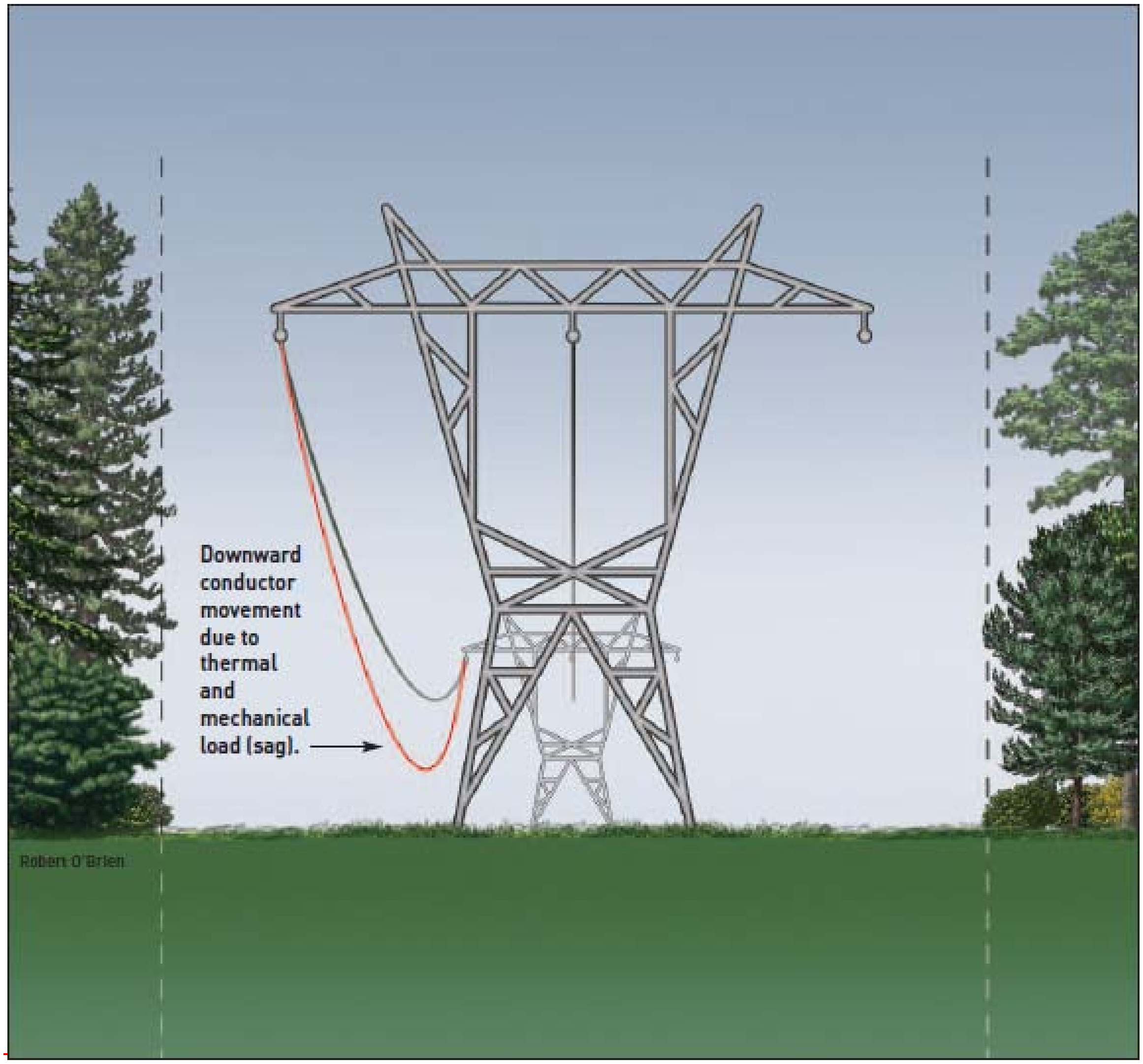
In order for a Transmission Owner to develop a specific maintenance approach, it is important to understand the dynamics of a line conductor's movement. This paper will first address the complexities inherent in observing and predicting conductor movement, particularly for field personnel. It will then present some examples of maintenance approaches which Transmission Owners may consider that take into account these complexities, while resulting in practical approaches for field personnel.

Additionally, it is important the Transmission Owner consider all conductor locations, the MVCD, and vegetation growth between maintenance activities when developing a maintenance approach.

Understanding Conductor Position and Movement

The conductor's position in space at any point in time is continuously changing as a reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading.

As a consequence of these loading variables, the conductor's position in space is dynamic and moving. When calculating the range of conductor positions, the Transmission Owner should use the same design criteria and assumptions that the Transmission Owner uses when establishing Ratings and SOL, as described in other standards. Typically, the greatest conductor movement would be at mid-span. As the conductor moves through various positions, a spark-over zone surrounding the conductor moves with it. The radius of the spark-over zone may be found by referring to Table 1 ("Minimum Vegetation Clearance Distances") in the standard. For illustrations of this zone and conductor movements, Figures ~~4~~1 through ~~6~~3 below demonstrate these concepts. At the time of making a field observation, however, it is very difficult to precisely know where the conductor is in relation to its wide range of all possible positions. Therefore, Transmission Owners must adopt maintenance approaches that account for this dynamic situation.


Downward conductor movement due to thermal and mechanical load (sag).
Robert O'Brien

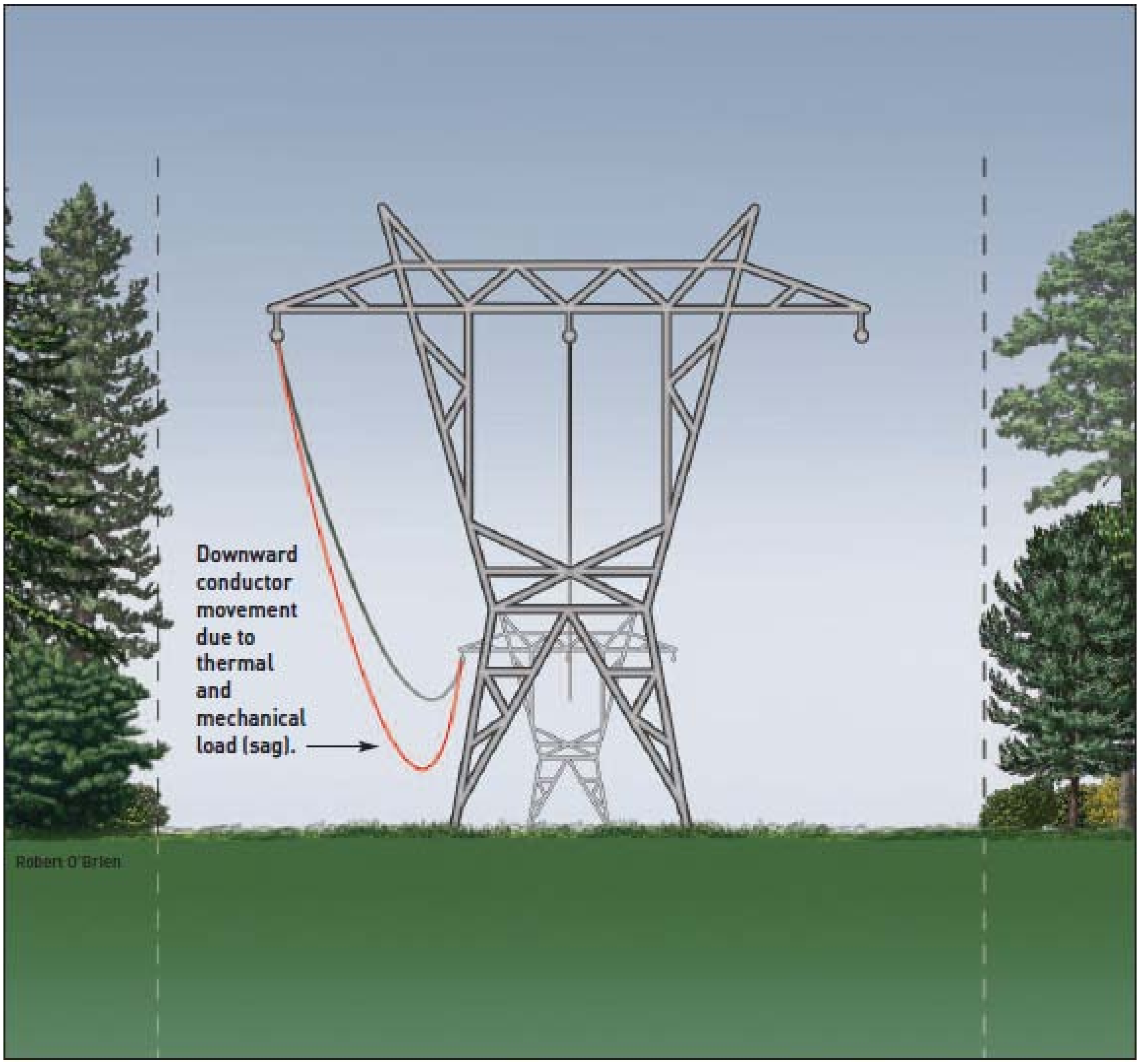
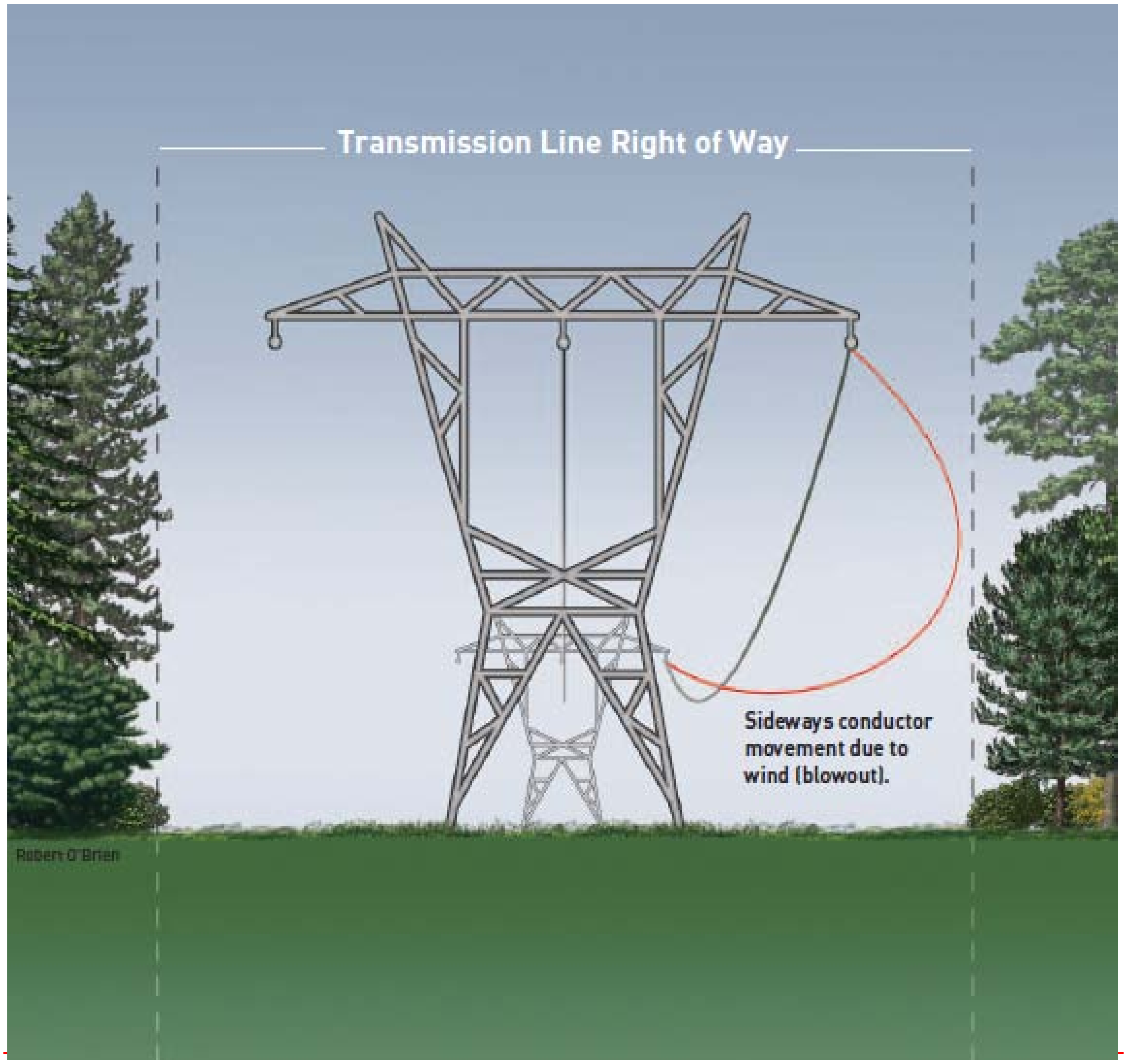

Downward
conductor
movement
due to
thermal
and
mechanical
load (sag).
Robert O'Brien

Figure ~~4~~1


Transmission Line Right of Way
Sideways conductor movement due to wind (blowout).
Robert O'Brien

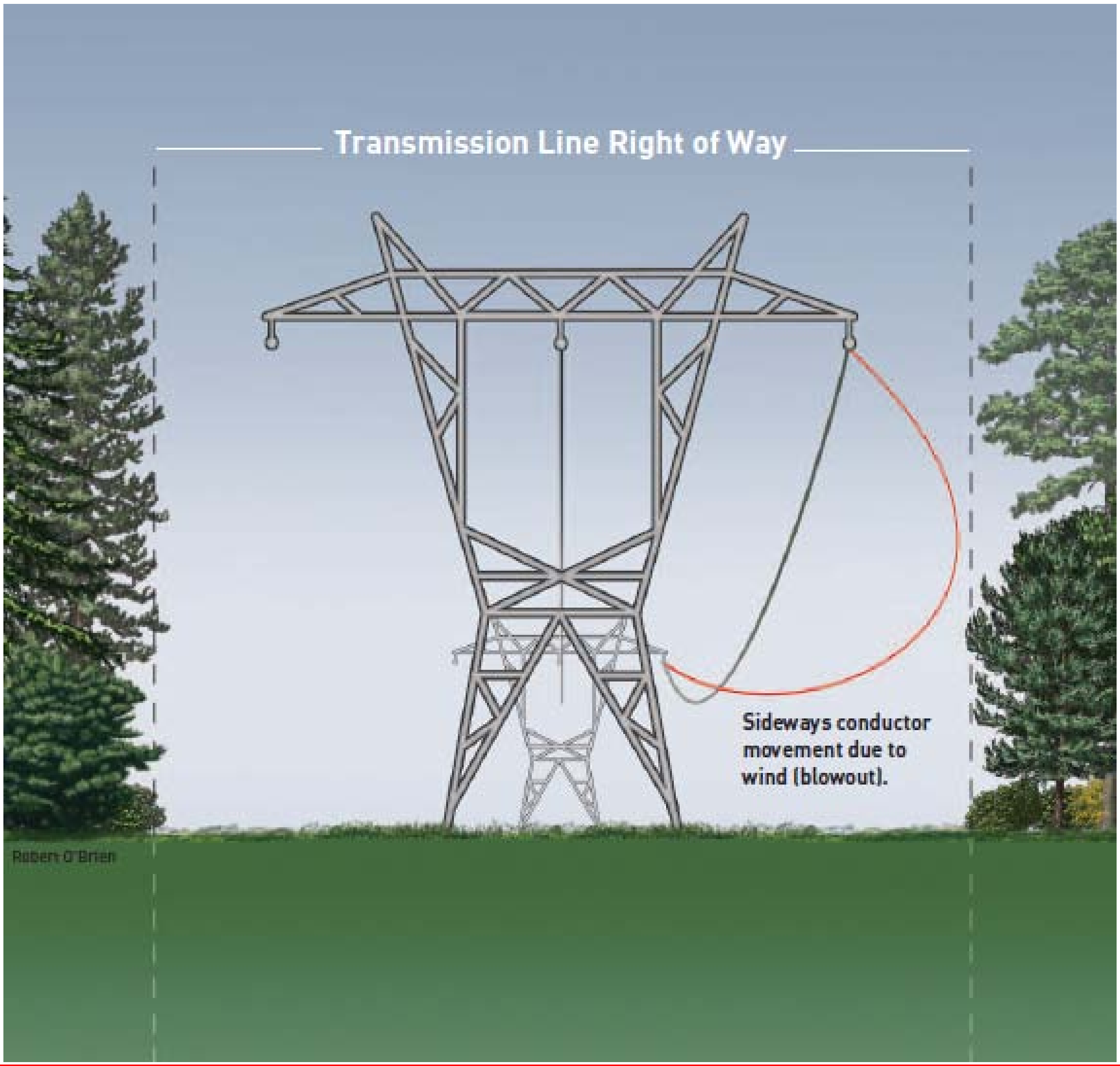
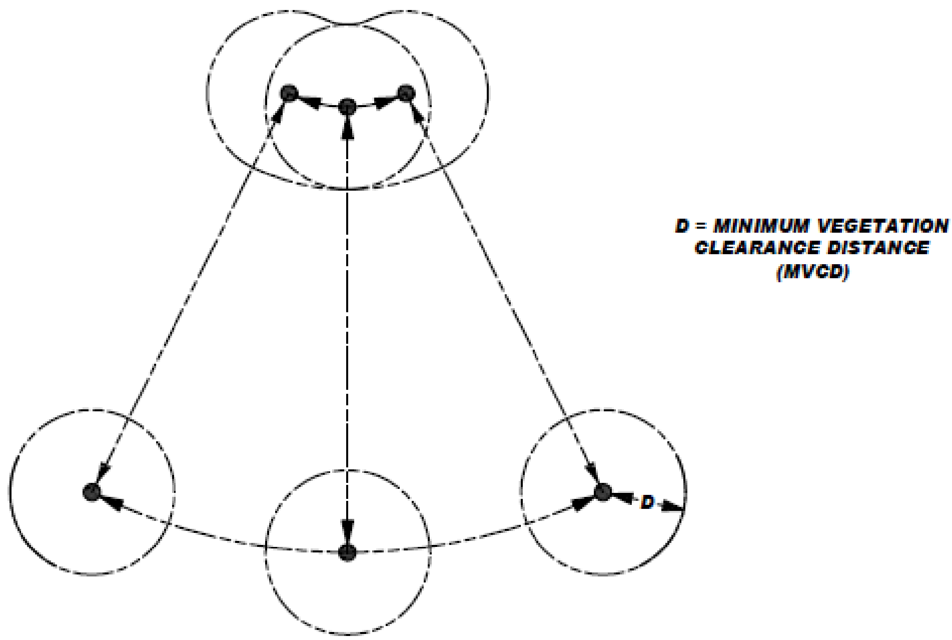
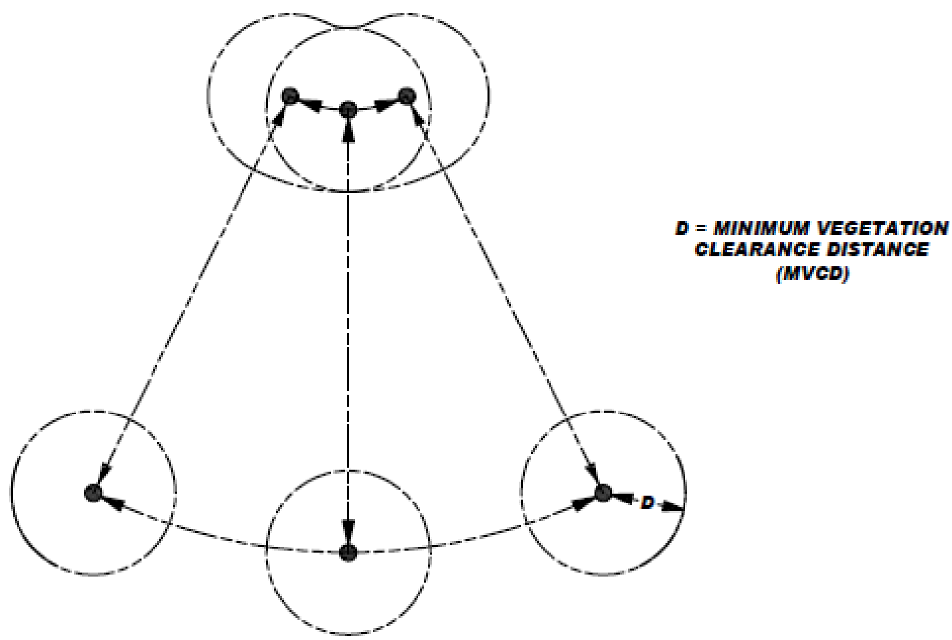

Transmission Line Right of Way
Sideways conductor movement due to wind (blowout).
Robert O'Brien

Figure ~~5~~2





Cross-Section View of a Single Conductor

At a Given Point Along The Span

Showing Six Possible Conductor Positions Due to Movement

Resulting From Thermal and Mechanical Loading

For Consideration in Developing a Maintenance Approach

Figure ~~6~~3

Selecting a Maintenance Approach

In order to maintain adequate separation between vegetation and transmission line conductors, the Transmission Owner must craft a maintenance strategy that keeps vegetation well away from the spark-over zone mentioned above. In fact, it is generally necessary to incorporate a variety of maintenance strategies. For example, one Transmission Owner may utilize a combination of routine cycles, traditional IVM techniques and long-term planning. Another Transmission Owner may place a higher reliance on frequent inspections and quick remediation as opposed to a cyclical approach. This variation of approaches is further warranted when factors, such as terrain, legal and other constraints, vegetation types, and climates, are considered in developing a Transmission Owner's specific approach to satisfying this requirement.

The following is a sample description of one combination of strategies which may be utilized by a Transmission Owner. A Transmission Owner's basic maintenance approach could be to remove all incompatible vegetation from the right of way if it has the right to do so and has no constraints. In mountainous terrain, however, this strategy could change to one where the Transmission Owner manages vegetation based on vegetation-to-conductor clearances, since it might not be necessary to remove vegetation in a valley that is far below.
If faced with constraints and assuming a line design with sufficient ground clearance, the Transmission Owner 's approach could then be to allow vegetation such as fruit trees, but perhaps only up to a given height at maturity (perhaps 10 feet from the ground). If constraints cannot be overcome and if design clearances are sufficient, an exception to the Transmission Owner's 10-foot guideline might be made. Finally, if the Transmission Owner has chosen to utilize vegetation-to-conductor clearance distance methods, the Transmission Owner could have an inspection regimen in place to regularly ensure that any impending clearance problems are identified early for rectification.

ANSI A300 – Best Management Practices for Tree Care Operations

A description of ANSI A-300, part 7, is offered below to illustrate another maintenance approach that could be used in developing a comprehensive transmission vegetation management program.

Introduction

Integrated Vegetation Management (IVM) is a best management practice conveyed in the American National Standard for Tree Care Operations, Part 7 (ANSI 2006) and the International Society of Arboriculture *Best Management Practices: Integrated Vegetation Management* (Miller 2007). IVM is consistent with the requirements in FAC-003-02, and it provides practitioners with what industry experts consider to be appropriate techniques to apply to electric right-of-way projects in order to meet or exceed the Standard.

IVM is a system of managing plant communities whereby managers set objectives; identify compatible and incompatible vegetation; consider action thresholds; and evaluate, select and implement the most appropriate control method or methods to achieve set objectives. The choice of control method or methods should be based on the environmental impact and anticipated effectiveness; along with site characteristics, security, economics, current land use and other factors.

Planning and Implementation

Best management practices provide a systematic way of planning and implementing a vegetation management program. While designed primarily with transmission systems in mind, it is also

applicable to distribution projects. As presented in ANSI A300 part 7 and the ISA best management practices, IVM consists of 6 elements:

1) Set Objectives
2) Evaluate the Site
3) Define Action Thresholds
4) Evaluate and Select Control Methods
5) Implement IVM
6) Monitor Treatment and Quality Assurance

The setting of objectives, defining action thresholds, and evaluating and selecting control methods all require decisions. The planning and implementation process is cyclical and continuous, because vegetation is dynamic and managers must have the flexibility to adjust their plans. Adjustments may be made at each stage as new information becomes available and circumstances evolve.

Set Objectives

Objectives should be clearly defined and documented. Examples of objectives can include promoting safety, preventing sustained outages caused by vegetation growing into electric facilities, maintaining regulatory compliance, protecting structures and security, restoring electric service during emergencies, maintaining access and clear lines of sight, protecting the environment, and facilitating cost effectiveness.

Objectives should be based on site factors, such as workload and vegetation type, in addition to human, equipment and financial resources. They will vary from utility to utility and project to project, depending on line voltage and criticality, as well as topographical, environmental, fiscal and political considerations. However, where it is appropriate, the overriding focus should be on environmentally-sound, cost effective control of species that potentially conflict with the electric facility, while promoting compatible, early successional, sustainable plant communities.

Work Load Evaluations

Work-load evaluations are inventories of vegetation that could have a bearing on management objectives. Work load assessments can capture a variety of vegetation characteristics, such as location, height, species, size and condition, hazard status, density and clearance from conductors. Assessments should be conducted considering voltage, conductor sag from ambient temperatures and loading, and the potential influence of wind on line sway.

Evaluate and Select Control Methods

Control methods are the process through which managers achieve objectives. The most suitable control method best achieves management objectives at a particular site. Many cases call for a combination of methods. Managers have a variety of controls from which to choose, including manual, mechanical, herbicide and tree growth regulators, biological, and cultural options.

Manual Control Methods

Manual methods employ workers with hand-carried tools, including chainsaws, handsaws, pruning shears and other devices to control incompatible vegetation. The advantage of manual techniques is that they are selective and can be used where others may not be. On the other hand, manual techniques can be inefficient and expensive compared to other methods.

Mechanical Control Methods

Mechanical controls are done with machines. They are efficient and cost effective, particularly for clearing dense vegetation during initial establishment, or reclaiming neglected or overgrown right of way. On the other hand, mechanical control methods can be non-selective and disturb sensitive sites.

Tree Growth Regulator and Herbicide Control Methods

Tree growth regulators and herbicides can be effective for vegetation management. Tree growth regulators (TGRs) are designed to reduce growth rates by interfering with natural plant processes. TGRs can be helpful where removals are prohibited or impractical by reducing the growth rates of some fast-growing species.

Herbicides control plants by interfering with specific botanical biochemical pathways. Herbicide use can control individual plants that are prone to re-sprout or sucker after removal. When trees that re-sprout or sucker are removed without herbicide treatment, dense thickets develop, impeding access, swelling workloads, increasing costs, blocking lines-of-site, and deteriorating wildlife habitat. Treating suckering plants allows early successional, compatible species to dominate the right-of-way and out-compete incompatible species, ultimately reducing work.

Cultural Control Methods

Cultural methods modify habitat to discourage incompatible vegetation and establish and manage desirable, early successional plant communities. Cultural methods take advantage of seed banks of native, compatible species lying dormant on site. In the long run, cultural control is the most desirable method where it is applicable.

A cultural control known as cover-type conversion provides a competitive advantage to short-growing, early successional plants, allowing them to thrive and eventually out-compete unwanted tree species for sunlight, essential elements and water. The early successional plant community is relatively stable, tree-resistant and reduces the amount of work, including herbicide application, with each successive treatment.

Wire-Border Zone

The wire-border zone technique is a management philosophy that can be applied through cultural control. W.C. Bramble and W.R. Byrnes developed it in the mid-1980s out of research begun in 1952 on a transmission right-of-way in the Pennsylvania State Game Lands 33 Research and Demonstration project (Yahner and Hutnik (2004).

The wire zone is the section of a utility transmission right-of-way directly under the wires and extending outward about 10 feet on each side. The wire zone is managed to promote a low-growing plant community dominated by grasses, herbs and small shrubs (under 3 feet in height at maturity). The border zone is the remainder of the right-of-way. It is managed to establish small trees and tall shrubs (under 25 feet in height at maturity). When properly managed, diverse, tree-resistant plant communities develop in wire and border zones. The communities not only protect the electric facility and reduce long-term maintenance, but also enhance wildlife habitat, forest ecology and aesthetic values.

Although the wire-border zone is a best practice in many instances, it is not necessarily universally suitable. For example, standard wire-border zone prescriptions may be unnecessary where lines are high off the ground, such as across low valleys or canyons, so the technique can be modified without sacrificing reliability.

One way to accommodate variances in topography is to establish different regions based on wire height. For example, over canyon bottoms or other areas where conductors are 100 feet or more above the ground, only a few trees are likely to be tall enough to conflict with the lines. In those cases, trees that potentially interfere with the transmission lines can be removed selectively on a case-by-case basis.

In areas where the wire is lower, perhaps between 50-100 feet from the ground, a border zone community can be developed throughout the right-of-way. Note that in many cases, conductor attachment points are more than 50 feet off the ground, so a border zone community can be cultivated near structures. Where the line is less than 50 feet off the ground, managers could apply a full wire-border zone prescription.

An environmental advantage of this type of modification is stream protection. Streams often course through the valleys and canyons where lines are likely to be elevated. Leaving timber or border zone communities in canyon bottoms helps shelter this valuable habitat, enabling managers to achieve environmentally sensitive objectives.

Implement IVM

All laws and regulations governing IVM practices and specifications written by qualified vegetation managers must be followed. Integrated vegetation management control methods should be implemented on regular work schedules, which are based on established objectives and completed assessments. Work should progress systematically, using control measures determined to be best for varying conditions at specific locations along a right-of-way. Some considerations used in developing schedules include the importance and type of line, vegetation clearances, work loads, growth rate of predominant vegetation, geography, accessibility, and in some cases, time lapsed since the last scheduled work.

Clearances Following Work

Clearances following work should be sufficient to meet management objectives, including preventing trees from entering the Minimum Vegetation Clearance Distance, electric safety risks, service-reliability threats and cost.

Monitor Treatment and Quality Assurance

An effective program includes documented processes to evaluate results. Evaluations can involve quality assurance while work is underway and after it is completed. Monitoring for quality assurance should begin early to correct any possible miscommunication or misunderstanding on the part of crewmembers. Early and consistent observation and evaluation also provides an opportunity to modify the plan, if need be, in time for a successful outcome.

Utility vegetation management programs should have systems and procedures in place for documenting and verifying that vegetation management work was completed to specifications. Post-control reviews can be comprehensive or based on a statistically representative sample. This final review points back to the first step and the planning process begins again.

Summary of A-300 example
Integrated Vegetation Management offers among others, a systematic way of planning and implementing a vegetation management program as presented in ANSI A300 Part 7. This methodology enables a program to comply with the NERC *Transmission Vegetation Management Program* standard (FAC-003-2). Managers should select control options to best promote management objectives.

Vegetation Inspections
As with the ANSI A-300 example, The Transmission Owner's transmission vegetation management program (TVMP) establishes the frequency of vegetation inspections based upon many factors. Such local and environmental factors may include anticipated growth rates of the local vegetation, length of the growing season for the geographical area, limited ~~Active Transmission~~ Rights of Way width, rainfall amounts, etc.

Annual Work Plan
Requirement R7 of the Standard addresses the execution of the annual work plan. A comprehensive approach that exercises the full extent of legal rights is superior to incremental management in the long term because it reduces overall encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient at all locations on the ~~Active Transmission Line~~ Right of Way. Removal is superior to pruning. Removal minimizes the possibility of conflicts between energized conductors and vegetation. Since this is not always possible, the Transmission Owner's approach should be to use its prescribed vegetation maintenance methods to work towards or achieve the maximum use of the ~~Active Transmission Line~~ Right of Way.

Requirement R4

R4. *Each Transmission Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable transmission line when ~~qualified personnel confirm~~the Transmission Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment.*

Rationale
To ensure expeditious communication between ~~qualified field personnel~~the Transmission Owner and ~~proper operating personnel~~the control center when a critical situation is confirmed.
~~Qualified field personnel may include~~

[VRF – Medium] [Time Horizon – Real-time]

M4. *Each Transmission Owner that has a confirmed vegetation condition likely to cause a Fault at any moment~~, as confirmed by qualified personnel,~~ will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)*

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the Transmission Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of a ~~qualified~~Transmission Owner's employee who personally identifies such a threat in the field. Confirmation could also be made by sending out ~~a qualified person~~an employee to evaluate a situation reported by a landowner~~ or an unqualified employee.~~.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The Transmission Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or positioning the system in recognition of the increasing risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some Transmission Owners may have a danger tree identification

program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5

R5. *~~Each~~ When a Transmission Owner ~~shall take corrective action when it~~ is constrained from performing ~~planned~~ vegetation work, ~~where a transmission line is put at potential risk due to~~ and the constraint~~.~~ may lead to a vegetation encroachment into the MVCD of its applicable transmission lines prior to the implementation of the next annual work plan then the Transmission Owner shall take corrective action to ensure continued vegetation management to prevent encroachments. [VRF – Medium] [Time Horizon – Operations Planning]*

Rationale

Legal actions and other events may occur which result in constraints that prevent the Transmission Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the Transmission Owner to put interim measures in place, rather than do nothing. ~~For example, in the 2003 NE blackout a Transmission Owner was prevented by a court order from performing planned work. However, when the court order expired, the TO failed to take action to maintain the~~

M5. *Each Transmission Owner has evidence of the corrective action taken for each constraint where ~~a~~an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, and evidence that a line was de-energized. (R5)*

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the Transmission Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the Transmission Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the Transmission Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the Transmission Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the Transmission Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the Transmission Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for each location.
- In developing the specific action to mitigate the potential risk to the transmission line the Transmission Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The Transmission Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6

R6. *Each Transmission Owner shall perform a Vegetation Inspection of ~~all~~100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year~~.~~ and with no more than 18 months between inspections on the same ROW.*[3]

[VRF – Medium] [Time Horizon – Operations Planning]

M6. *Each Transmission Owner has evidence that it conducted Vegetation Inspections ~~at least once per calendar year for applicable~~of the transmission ~~lines~~line ROW for all applicable transmission lines at least once per calendar year but with no more than 18 months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)*

> ~~**Rationale**~~
> ~~Inspections are used by Transmission Owners to prevent the encroachment of vegetation into the MVCD and provide a basis for assessing risk. This requirement sets a minimum vegetation inspection frequency of once per calendar year. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.~~
> frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections that fits general industry practice. In addition, the fact that Vegetation Inspections can be performed in conjunction with general line inspections further facilitates a Transmission Owner's ability to meet this requirement. However, the Transmission Owner may determine that more frequent inspections are needed to maintain reliability levels, dependent upon such factors as anticipated growth rates of the local vegetation, length of the growing season for the geographical area, limited ~~Active Transmission~~ ROW width, and rainfall amounts. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The SDT added footnote 3 to address the situation where a Transmission Owner through no fault of its own, would be unable to complete the vegetation inspection within the allotted time period. This would include the situation of mutual aid as well as disasters to the Transmission Owner's own system.

The VSL for Requirement R6 has VSL categories ranked by the percentage of the required ROW inspections completed. To calculate the percentage of inspection completion, the Transmission Owner may choose units such as: line miles or kilometers, circuit miles or kilometers, pole line miles, ROW miles, etc.

[3] When the Transmission Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO is granted a time extension that is equivalent to the duration of the time the TO was prevented from performing the Vegetation Inspection.

For example, when a Transmission Owner operates 2,000 miles of 230 kV transmission lines this Transmission Owner will be responsible for inspecting all 2,000 miles of 230 kV transmission lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The “Low VSL” for R6 would apply in this example.

Requirement R7

R7. *Each Transmission Owner shall complete ~~the work in an~~100% of its annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made ~~and documented~~ (provided they do not put the transmission system at risk of a vegetation encroachment~~.~~) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include:*

- Change in expected growth rate/ environmental factors
- ~~*Major storms*~~
- Circumstances that are beyond the control of a Transmission Owner[4]
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- ~~*Funding adjustments (increase or decrease)*~~
- Emerging technologies

  [VRF – Medium] [Time Horizon – Operations Planning]

Rationale
This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. An annual vegetation work plan allows for work to be modified for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that the changes do not violate the encroachment within the MVCD.

M7. *Each Transmission Owner has evidence that it completed its annual vegetation work plan. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (including modifications if any), dated work orders, dated invoices, or dated inspection records. (R7)*

R7 is a risk-based requirement. The Transmission Owner is required to implement an annual work plan for vegetation management to accomplish the purpose of this Standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a “span-by-span”, or even a “line-by-line” detailed description of all work to be performed. It is only intended to require that the Transmission Owner provide evidence of annual planning and execution of a vegetation

[4] circumstances that are beyond the control of a Transmission Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, major storms as defined either by the TO or an applicable regulatory body, ice storms, and floods; arboricultural, horticultural or agricultural activities.

management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

The ability to modify the work plan allows the Transmission Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance~~.~~ or work may be deferred to a subsequent year because of slower-than-expected growth. This situation may also include complying with mutual assistance agreements by moving resources off the Transmission Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan. Modifications to the annual work plan must always ensure the reliability of the electric Transmission system.

In general, the vegetation management maintenance approach should use the full extent of the Transmission Owner's ~~easement, fee simple and other~~ legal rights ~~allowed.~~ on the ROW. A comprehensive approach that exercises the full extent of legal rights on the ~~Active Transmission Line~~ ROW is superior to incremental management in the long term because it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan, the Transmission Owner should allow time for reasonable and predictable procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases, the lead time for obtaining permits may necessitate preparing work plans more than a year prior to ~~work~~the start ~~dates~~of work. Transmission Owners may also need to consider those special landowner requirements ~~as documented in easement instruments~~.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the Transmission Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs~~,~~ and walk-through reports.

Appendix 1: Clearance Distance Derivation by the Gallet Equation

The Gallet Equation is a well-known method of computing the required strike distance for proper insulation coordination, and has the ability to take into account various air gap geometries, as well as non-standard atmospheric conditions. When the Gallet Equation and conservative probabilistic methods are combined, i.e. deterministic design, sparkover probabilities of 10^{-6} or less are achieved. This approach is well known for its conservatism and was used to design the first 500 kV and 765 kV lines in North America [1]. Thus, the deterministic design approach using the Gallet Equation is used for the standard to compute the minimum strike distance between transmission lines and the vegetation that may be present in or along the transmission corridor.

Method Explanation (Gallet Equation)

In 1975 G. Gallet published a benchmark paper that provided a method to compute the critical flashover voltage (CFO) of various air gap geometries [4]. The Gallet Equation uses various "gap factors" to take into account various air gap geometries. Various gap factor values are provided in [1]. If the vegetation in a transmission corridor, e.g. a tree, is assumed electrically to be a large structure then the CFO of such an air gap geometry can be computed for dry or wet conditions using a well established equation proposed by Gallet [1],[2],[4],

$$CFO_A = k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} \quad (1)$$

where,

k_w is defined as the factor that takes into account wet or dry conditions (dry = 1.0 and wet = 0.96) and phase arrangement (multiply by 1.08 for outside phase), e.g. outside phase and wet conditions = (0.96)(1.08) = 1.037,

k_g is defined as the gap factor (1.3 for conductor to large structure),

D is the strike distance (m),

CFO_A is the CFO for the relative air density (kV).

δ is defined as the relative air density and is approximately equal to (2) where A is the altitude in km,

$$\delta = e^{-\frac{A}{8.6}} \quad (2)$$

$$m = 1.25 G_0 \left(G_0 - 0.2\right) \quad (3)$$

$$G_0 = \frac{CFO_s}{500 \cdot D} \quad (4)$$

$$CFO_s = k_w \cdot k_g \cdot \frac{3400}{1+\frac{8}{D}} \tag{5}$$

where CFO_S is the CFO for standard atmospheric conditions (kV). Using (1)-(5), the required CFO_A can be computed using an iterative process.

Once the CFO_A is known, deterministic methods can be used to determine the required clearance distance. If we let the maximum switching overvoltage be equal to the withstand voltage of the air gap (CFO_A - 3σ) then the CFO_A can be written as (6).

$$CFO_A = \frac{V_m}{1-3\left(\frac{\sigma}{CFO_A}\right)} \tag{6}$$

where

V_m is equal to the maximum switching overvoltage, i.e. the value that has a 0.135% chance of being exceeded,

σ is the standard deviation of the air gap insulation,

CFO_A is the critical flashover voltage of the air gap insulation under non-standard atmospheric conditions.

The ratio of σ to the CFO_A given in (6) can be assumed to be 0.05 (5%) [1]. Thus, (6) can be written as (7).

$$CFO_A = \frac{V_m}{0.85} \tag{7}$$

Substituting (7) into (1) we arrive at (8).

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} \tag{8}$$

Equation 8 relates the maximum transient overvoltage, V_m, to the air gap distance, D. Using (8) to compute the required clearance distance for the specified air gap geometry (conductor to large structure) results in a probability of flashover in the range of 10^{-6}.

Transient Overvoltage

In general, the worst case transient overvoltages occurring on a transmission line are caused by energizing or re-energizing the line with the latter being the extreme case if trapped charge is present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to sparkover from the line conductor to nearby vegetation. Thus, the worst case scenarios that are typically analyzed for insulation coordination purposes (e.g. line energization and re-energization) can be ignored. For the purposes of FAC-003-2, the worst case transient overvoltage then becomes the maximum value that can occur with the line energized. Determining a realistic value of transient overvoltage for this situation is difficult because the maximum transient overvoltage factors listed in the literature are based on a

switching operation of the line in question. In other words, these maximum overvoltage values (e.g. the values listed in [2], [3] and [5]) are based on the assumption that the subject line is being energized, re-energized or de-energized. These operations, by their very nature, will create the largest transient overvoltages. Typical values of transient overvoltages of in-service lines, as such, are not readily available in the literature because the resulting level of overvoltage is negligible compared with the maximum (e.g. re-energizing a transmission line with trapped charge). A conservative value for the maximum transient overvoltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 p.u.[2]. This value is a conservative estimate of the transient overvoltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without a pre-insertion device (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. 362 kV), the maximum transient overvoltage of an "in-service" ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 p.u. or less [2]. It is well known that these theoretical transient overvoltages will not be experienced at locations remote from the bus at which they were created; however, in order to be conservative, it will be assumed that all nearby ac lines are subjected to this same level of overvoltage. Thus, a maximum transient overvoltage factor of 2.0 p.u. for 242 kV and below and 1.4 p.u. for ac transmission lines 362 kV and above is used to compute the required clearance distances for vegetation management purposes.

The overvoltage characteristics of dc transmission lines vary somewhat from their ac counterparts. The referenced empirically derived transient overvoltage factor used to calculate the minimum clearance distances from dc transmission lines to vegetation for the purpose of FAC-003-2 will be 1.8 p.u.[3].

Example Calculation

An example calculation is presented below using the proposed method of computing the vegetation clearance distances. It is assumed that the line in question has a maximum operating voltage of 550 kV_{rms} line-to-line. Using a per unit transient overvoltage factor of 1.4, the result is a peak transient voltage of 629 kV_{crest}. It is further assumed that the line in question operates at a maximum altitude of 7000 feet (2.134 km) above sea level.

The required withstand voltage of the air gap must be equal to or greater than 629 kV_{crest}. Since the altitude is above sea level, (1) - (5) have to be iterated on to achieve the desired result. Equation (9) can be used as an initial guess for the clearance distance.

$$D_i = \frac{8}{\dfrac{3400 \cdot k_w \cdot k_g}{\left(\dfrac{V_m}{0.85}\right)} - 1} \tag{9}$$

For our case here, V_m is equal to 629 kV, k_w = 1.037 and k_g = 1.3. Thus,

$$D_i = \frac{8}{\dfrac{3400 \cdot k_w \cdot k_g}{\left(\dfrac{V_m}{0.85}\right)} - 1} = \frac{8}{\dfrac{3400 \cdot 1.037 \cdot 1.3}{\left(\dfrac{629}{0.85}\right)} - 1} = 1.535m \tag{10}$$

Using (2)-(5) and (8) the withstand voltage of the air gap is next computed. This value will then be compared to the maximum transient overvoltage.

$$CFO_S = k_w \cdot k_g \cdot \frac{3400}{1+\frac{8}{D}} = 1.037 \cdot 1.3 \cdot \frac{3400}{1+\frac{8}{1.535}} = 737.7kV \tag{11}$$

$$\delta = e^{-\frac{A}{8.6}} = e^{-\frac{2.134}{8.6}} = 0.78 \tag{12}$$

$$G_O = \frac{CFO_S}{500 \cdot D} = \frac{737.7}{(500)\cdot(1.535)} = 0.961 \tag{13}$$

$$m = 1.25 \cdot G_O(G_O - 0.2) = 1.25 \cdot 0.961(0.961 - 0.2) = 0.915 \tag{14}$$

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} = (0.85)(1.037)(1.3)(0.78)^{0.915}\left(\frac{3400}{1+\frac{8}{1.535}}\right) = 499.8kV \tag{15}$$

The calculated V_m is less than 629 kV; thus, the clearance distance must be increased. A few iterations using (2)-(5) and (8) are required until the computed $V_m \geq 629$ kV. For this case it was found that D = 1.978 m (6.49 feet) yielded V_m = 629.3 kV. Using this clearance distance the following values were computed for the final iteration.

$$CFO_S = k_w \cdot k_g \cdot \frac{3400}{1+\frac{8}{D}} = 1.037 \cdot 1.3 \cdot \frac{3400}{1+\frac{8}{1.978}} = 908.5kV \tag{16}$$

$$\delta = e^{-\frac{A}{8.6}} = e^{-\frac{2.134}{8.6}} = 0.78 \tag{17}$$

$$G_O = \frac{CFO_S}{500 \cdot D} = \frac{908.5}{(500)\cdot(1.978)} = 0.919 \tag{18}$$

$$m = 1.25 \cdot G_O(G_O - 0.2) = 1.25 \cdot 0.919(0.919 - 0.2) = 0.825 \tag{19}$$

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} = (0.85)(1.037)(1.3)(0.78)^{0.825}\left(\frac{3400}{1+\frac{8}{1.978}}\right) = 629.3kV \tag{20}$$

Therefore, the minimum vegetation clearance distance for a maximum line to line ac operating voltage of 550 kV at 7000 feet above sea level is 1.978 m (6.49 feet). Table 1 provides calculated distances for various altitudes and maximum system operating ac voltages.

TABLE 1 — Minimum Vegetation Clearance Distances (MVCD)[6]
For **Alternating Current** Voltages

(AC) Nominal System Voltage (kV)	**(AC) Maximum System Voltage (kV)**	**MVCD feet (meters) sea level**	**MVCD feet (meters) 3,000ft (914.4m)**	**MVCD feet (meters) 4,000ft (1219.2m)**	**MVCD feet (meters) 5,000ft (1524m)**	**MVCD feet (meters) 6,000ft (1828.8m)**	**MVCD feet (meters) 7,000ft (2133.6m)**	**MVCD feet (meters) 8,000ft (2438.4m)**	**MVCD feet (meters) 9,000ft (2743.2m)**	**MVCD feet (meters) 10,000ft (3048m)**	**MVCD feet (meters) 11,000ft (3352.8m)**
765	800	8.06ft (2.46m)	8.89ft (2.71m)	9.17ft (2.80m)	9.45ft (2.88m)	9.73ft (2.97m)	10.01ft (3.05m)	10.29ft (3.14m)	10.57ft (3.22m)	10.85ft (3.31m)	11.13ft (3.39m)
500	550	5.06ft (1.54m)	5.66ft (1.73m)	5.86ft (1.79m)	6.07ft (1.85m)	6.28ft (1.91m)	6.49ft (1.98m)	6.7ft (2.04m)	6.92ft (2.11m)	7.13ft (2.17m)	7.35ft (2.24m)
345	362	3.12ft (0.95m)	3.53ft (1.08m)	3.67ft (1.12m)	3.82ft (1.16m)	3.97ft (1.21m)	4.12ft (1.26m)	4.27ft (1.30m)	4.43ft (1.35m)	4.58ft (1.40m)	4.74ft (1.44m)
230	242	2.97ft (0.91m)	3.36ft (1.02m)	3.49ft (1.06m)	3.63ft (1.11m)	3.78ft (1.15m)	3.92ft (1.19m)	4.07ft (1.24m)	4.22ft (1.29m)	4.37ft (1.33m)	4.53ft (1.38m)
161*	169	2ft (0.61m)	2.28ft (0.69m)	2.38ft (0.73m)	2.48ft (0.76m)	2.58ft (0.79m)	2.69ft (0.82m)	2.8ft (0.85m)	2.91ft (0.89m)	3.03ft (0.92m)	3.14ft (0.96m)
138*	145	1.7ft (0.52m)	1.94ft (0.59m)	2.03ft (0.62m)	2.12ft (0.65m)	2.21ft (0.67m)	2.3ft (0.70m)	2.4ft (0.73m)	2.49ft (0.76m)	2.59ft (0.79m)	2.7ft (0.82m)
115*	121	1.41ft (0.43m)	1.61ft (0.49m)	1.68ft (0.51m)	1.75ft (0.53m)	1.83ft (0.56m)	1.91ft (0.58m)	1.99ft (0.61m)	2.07ft (0.63m)	2.16ft (0.66m)	2.25ft (0.69m)
88*	100	1.15ft (0.35m)	1.32ft (0.40m)	1.38ft (0.42m)	1.44ft (0.44m)	1.5ft (0.46m)	1.57ft (0.48m)	1.64ft (0.50m)	1.71ft (0.52m)	1.78ft (0.54m)	1.86ft (0.57m)
69*	72	0.82ft (0.25m)	0.94ft (0.29m)	0.99ft (0.30m)	1.03ft (0.31m)	1.08ft (0.33m)	1.13ft (0.34m)	1.18ft (0.36m)	1.23ft (0.37m)	1.28ft (0.39m)	1.34ft (0.41m)

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above).

[6] The distances in this Table are the minimums required to prevent Flashover; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

TABLE 1 (CONT.) — Minimum Vegetation Clearance Distances (MVCD)
For **Direct Current** Voltages

(DC) Nominal Pole to Ground Voltage (kV)	**MVCD feet (meters) sea level**	**MVCD feet (meters) 3,000ft (914.4m) Alt.**	**MVCD feet (meters) 4,000ft (1219.2m) Alt.**	**MVCD feet (meters) 5,000ft (1524m) Alt.**	**MVCD feet (meters) 6,000ft (1828.8m) Alt.**	**MVCD feet (meters) 7,000ft (2133.6m) Alt.**	**MVCD feet (meters) (8,000ft (2438.4m) Alt.**	**MVCD feet (meters) 9,000ft (2743.2m) Alt.**	**MVCD feet (meters) 10,000ft (3048m) Alt.**	**MVCD feet (meters) 11,000ft (3352.8m) Alt.**
±750	13.92ft (4.24m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.9ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.07ft (3.07m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	(13.54ft 4.13m)
±500	7.89ft (2.40m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	4.78ft (1.46m)	5.35ft (1.63m)	5.55ft (1.69m)	5.75ft (1.75m)	5.95ft (1.81m)	6.15ft (1.87m)	6.36ft (1.94m)	6.57ft (2.00m)	6.77ft (2.06m)	6.98ft (2.13m)
±250	3.43ft (1.05m)	4.02ft (1.23m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5ft (1.52m)	5.17ft (1.58m)

List of Acronyms and Abbreviations

ANSI	American National Standards Institute
IEEE	Institute of Electrical and Electronics Engineers
IVM	Integrated Vegetation Management
NERC	North American Electric Reliability Corporation

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Standards Announcement

Successive Ballot and Non-binding Poll Open
Project 2007-07 – Vegetation Management
February 18 – February 28, 2011

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Project 2007-07 – Vegetation Management

A successive ballot window for FAC-003-2 – Transmission Vegetation Management and its associated implementation plan is open through **8 p.m. on February 28, 2011**.

In addition, members of this ballot pool will be able to vote in a concurrent non-binding poll on the standard's Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs). Members who joined the ballot pool to vote on the standard were automatically entered in a separate pool to participate in the non-binding poll for the VRFs and VSLs. The non-binding poll will appear in the list of current ballots, and is labeled accordingly.

Instructions

Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Background

FAC-003-1 is being revised to address several fill-in-the-blank requirements, directives from Order 693, and issues raised by stakeholders. An initial ballot closed in July 2010 and achieved a quorum of 86.18 % and an approval of 65.93 %. The drafting team has posted its consideration of comments received, both those submitted with a ballot as well as those submitted with a comment form. In addition, a Quality Review was conducted in November 2010, and the drafting team revised the draft standard and technical reference in response to comments and input from the Quality Review.

Documents for this project, including clean and redline to the last posted versions of the standard, implementation plan, and technical reference and an unofficial copy of the questions listed in the comment forms are posted on the project web page at:
http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

Next Steps

Voting results will be posted and announced after the ballot window closes, and the drafting team will consider all comments, including those submitted with a comment form and those submitted with a ballot.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

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Standards Announcement

Project 2007-07 Transmission Vegetation Management
Successive Formal Comment Period Open
January 27, 2010 – February 28, 2011

Now available at:
http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

A 30-day formal comment period for the proposed standard, FAC-003-2 – Transmission Vegetation Management, its associated implementation plan, and supporting technical reference paper is now open **until 8 p.m. Eastern on February 28, 2011**.

Background

FAC-003-1 is being revised to address several fill-in-the-blank requirements, directives from Order 693, and issues raised by stakeholders. An initial ballot closed in July 2010. The ballot achieved a quorum of 86.18 % and an approval of 65.93 %. The drafting team has posted its Consideration of Comments received (those submitted with a ballot as well as those submitted with a comment form). A Quality Review was conducted in November 2010 and the drafting team has revised the draft standard and technical reference in response to comments and input from the Quality Review.

Documents for this project, including clean and redline to the last posted versions of the standard, implementation plan, and technical reference and an unofficial copy of the questions listed in the comment forms are posted at the following site:
http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

Instructions

Please use this electronic form to submit comments on FAC-003-2, its associated implementation plan, and supporting technical reference paper. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net.

Next Steps – Successive Ballot and Non-binding Poll of VRFs and VSLs

A successive ballot will be conducted during the last 10 days of the formal comment period, from 8 a.m. Eastern on Friday, February 18, 2011 until 8p.m. Eastern on Monday, February 28, 2011. All members of the ballot pool must cast a new ballot since the votes and comments from the last ballot will not be carried over. In addition, members of the ballot pool will need to cast a new opinion on the revised VRFs and VSLs. The drafting team will consider all comments (those submitted with a comment form, and those submitted with a ballot or with the non-binding poll) and will determine whether to make additional changes to the standard and its implementation plan.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

For more information or assistance, please contact Monica Benson,
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Ballot Results	
Ballot Name:	Project 2007-07 Vegetation Management_in
Ballot Period:	2/18/2011 - 2/28/2011
Ballot Type:	Initial
Total # Votes:	241
Total Ballot Pool:	304
Quorum:	**79.28 % The Quorum has been reached**
Weighted Segment Vote:	79.34 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	90	1	59	0.776	17	0.224	2	12
2 - Segment 2.	9	0.3	3	0.3	0	0	1	5
3 - Segment 3.	74	1	45	0.776	13	0.224	5	11
4 - Segment 4.	22	1	9	0.643	5	0.357	4	4
5 - Segment 5.	54	1	31	0.838	6	0.162	2	15
6 - Segment 6.	35	1	18	0.783	5	0.217	0	12
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.3	2	0.2	1	0.1	2	2
9 - Segment 9.	6	0.6	6	0.6	0	0	0	0
10 - Segment 10.	7	0.5	4	0.4	1	0.1	0	2
Totals	**304**	**6.7**	**177**	**5.316**	**48**	**1.384**	**16**	**63**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert D Smith	Negative	View
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	View
1	Avista Corp.	Scott Kinney	Affirmative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Affirmative	View

1	BC Transmission Corporation	Gordon Rawlings	Affirmative	
1	Beaches Energy Services	Joseph S. Stonecipher	Negative	View
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	View
1	CenterPoint Energy	Paul Rocha	Negative	
1	Central Maine Power Company	Brian Conroy		
1	City of Vero Beach	Randall McCamish	Negative	View
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	View
1	Commonwealth Edison Co.	Daniel Brotzman		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	View
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	E.ON U.S.	Larry Monday		
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Negative	View
1	GDS Associates, Inc.	Claudiu Cadar	Abstain	
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	JEA	Ted E Hobson	Negative	View
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stan T. Rzad	Negative	View
1	Lake Worth Utilities	Walt Gill	Negative	View
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca	Negative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Negative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	Metropolitan Water District of Southern California	Ernest Hahn	Abstain	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	National Grid	Saurabh Saksena	Affirmative	View
1	Nebraska Public Power District	Richard L. Koch	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Henry G. Masti		
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Douglas G Peterchuck	Affirmative	
1	Oncor Electric Delivery	Michael T. Quinn	Affirmative	View
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson		
1	Pacific Gas and Electric Company	Chifong L. Thomas		
1	PacifiCorp	Mark Sampson		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Negative	View
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	
1	Potomac Electric Power Co.	Richard J Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	View
1	Public Service Company of New Mexico	Laurie Williams	Negative	View
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Chelan County	Chad Bowman	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	

1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	View
1	South Texas Electric Cooperative	Richard McLeon	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson		
1	Southern Illinois Power Coop.	William G. Hutchison	Negative	View
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Keith V Carman	Affirmative	View
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Brandy A Dunn	Affirmative	View
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	View
2	Alberta Electric System Operator	Mark B Thompson	Abstain	View
2	BC Transmission Corporation	Faramarz Amjadi		
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning		
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	Midwest ISO, Inc.	Jason L Marshall	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	View
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe		
2	Southwest Power Pool	Charles H Yeung		
3	Alabama Power Company	Richard J. Mandes	Affirmative	View
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	American Electric Power	Raj Rana		
3	APS	Steven Norris	Negative	View
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blue Ridge Power Agency	Duane S Dahlquist	Negative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	View
3	City of Bartow, Florida	Matt Culverhouse	Negative	View
3	City of Clewiston	Lynne Mila	Negative	
3	City of Green Cove Springs	Gregg R Griffin	Abstain	
3	City of Leesburg	Phil Janik	Negative	
3	Cleco Utility Group	Bryan Y Harper	Negative	View
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	View
3	Constellation Energy	Carolyn Ingersoll	Affirmative	
3	Consumers Energy	David A. Lapinski	Negative	View
3	Consumers Power Inc.	Roman Gillen	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	View
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Municipal Power Agency	Joe McKinney		
3	Florida Power Corporation	Lee Schuster	Affirmative	View
3	Gainesville Regional Utilities	Kenneth Simmons		
3	Georgia Power Company	Anthony L Wilson	Affirmative	View
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier		
3	Hydro One Networks, Inc.	Michael D. Penstone		
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory David Woessner	Negative	
3	Lakeland Electric	Mace Hunter	Affirmative	View
3	Lincoln Electric System	Bruce Merrill	Affirmative	View
3	Los Angeles Department of Water & Power	Kenneth Silver		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Affirmative	

3	MEAG Power	Steven Grego	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Abstain	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	Ocala Electric Utility	David T. Anderson	Negative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	OTP Wholesale Marketing	Bradley Tollerson		
3	PacifiCorp	John Apperson	Affirmative	
3	PECO Energy an Exelon Co.	Vincent J. Catania		
3	Platte River Power Authority	Terry L Baker	Negative	View
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Abstain	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salmon River Electric Cooperative	Ken Dizes	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson	Affirmative	
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	View
3	South Carolina Electric & Gas Co.	Hubert C. Young		
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Springfield Utility Board	Jeff Nelson	Abstain	
3	Tampa Electric Co.	Ronald L Donahey	Affirmative	
3	Turlock Irrigation District	Casey Hashimoto		
3	Umatilla Electric Cooperative	Steve Eldrige	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	View
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	American Municipal Power - Ohio	Kevin Koloini		
4	American Public Power Association	Allen Mosher	Abstain	
4	City of Clewiston	Kevin McCarthy	Negative	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Negative	
4	Consumers Energy	David Frank Ronk		
4	Cowlitz County PUD	Rick Syring	Negative	View
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards	Negative	View
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Affirmative	View
4	Modesto Irrigation District	Spencer Tacke	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	View
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Affirmative	View
5	Amerenue	Sam Dwyer	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	View
5	Chelan County Public Utility District #1	John Yale	Affirmative	
5	City of Grand Island	Jeff Mead	Abstain	
5	City of Tallahassee	Alan Gale	Affirmative	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	View
5	Consumers Energy	James B Lewis	Negative	View
5	Cowlitz County PUD	Bob Essex	Negative	View

5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Robert Smith		
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	View
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Cynthia E Sulzer		
5	JEA	Donald Gilbert		
5	Kansas City Power & Light Co.	Scott Heidtbrink	Negative	
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lincoln Electric System	Dennis Florom		
5	Louisville Gas and Electric Co.	Charlie Martin		
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	Michael K Wilkerson		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Otter Tail Power Company	Stacie Hebert		
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	View
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	
5	PPL Generation LLC	Mark A Heimbach		
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	View
5	Public Service Enterprise Group Incorporated	Dominick Grasso	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	South California Edison Company	Ahmad Sanati		
5	South Carolina Electric & Gas Co.	Richard Jones		
5	South Mississippi Electric Power Association	Jerry W Johnson		
5	Tenaska, Inc.	Scott M. Helyer	Negative	
5	Tennessee Valley Authority	George T. Ballew	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan		
5	U.S. Bureau of Reclamation	Martin Bauer P.E.		
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	View
6	AEP Marketing	Edward P. Cox	Affirmative	View
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	View
6	Cleco Power LLC	Matthew D Cripps	Negative	View
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	View
6	Constellation Energy Commodities Group	Brenda Powell		
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit		
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View
6	Florida Municipal Power Pool	Thomas E Washburn	Negative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	View
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Thomas Saitta	Negative	View
6	Lakeland Electric	Paul Shipps	Negative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	View
6	Louisville Gas and Electric Co.	Daryn Barker		
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	OTP Wholesale Marketing	Bruce Glorvigen		
6	PacifiCorp	Gregory D Maxfield		

6	Progress Energy	John T Sturgeon	Affirmative	View
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	RRI Energy	Trent Carlson		
6	Salt River Project	Mike Hummel		
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Western Area Power Administration - UGP Marketing	John Stonebarger		
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	View
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski		
8	Pacific Northwest Generating Cooperative	Margaret Ryan	Abstain	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon	Negative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Abstain	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	Oregon Public Utility Commission	Jerome Murray	Affirmative	
9	Public Service Commission of South Carolina	Philip Riley	Affirmative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Midwest Reliability Organization	Dan R Schoenecker		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith	Negative	View
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Southwest Power Pool Regional Entity	Stacy Dochoda		
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

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Account Log-In/Register

Standards Announcement

Project 2007-07 Transmission Vegetation Management
Successive Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Ballot Results for Revisions to FAC-003

A successive ballot on revisions to FAC-003 - Transmission Vegetation Management, and a concurrent non-binding poll of associated VRFs and VSLs concluded on February 28, 2011.

Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 79.28 %
Approval: 79.34 %

Violation Risk Factor (VRF) and Violation Severity Level (VSL) Non-binding Poll Results

For the non-binding poll of VRFs and VSLs, 77% of those who registered to participate provided an opinion; 79% of those who provided an opinion indicated support for the VRFs and VSLs that were proposed.

Next Steps

The drafting team will post its consideration of all comments (those submitted with a comment form, and those submitted with a ballot).

Background:

FAC-003-1 is being revised to address several fill-in-the-blank requirements, directives from Order 693, and issues raised by stakeholders. An initial ballot closed in July 2010 and achieved a quorum of 86.18 % and an approval of 65.93 %. The drafting team has posted its consideration of comments received, both those submitted with a ballot as well as those submitted with a comment form. In addition, a Quality Review was conducted in November 2010, and the drafting team revised the draft standard and technical reference in response to comments and input from the Quality Review.

Further details are available on the project page: http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
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Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2007-07 Vegetation Management Non-Binding Poll for VRFs and VSLs
Poll Period:	2/18/2011 - 2/28/2011
Total # Opinions:	187
Total Ballot Pool:	304
Summary Results:	77% of those who registered to participate provided an opinion; 79% of those who provided an opinion indicated support for the VRFs and VSLs that were proposed.

Individual Ballot Pool Results

Segment	Organization	Member	Opinion	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai		
1	Arizona Public Service Co.	Robert D Smith	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Abstain	
1	Avista Corp.	Scott Kinney	Affirmative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Affirmative	View
1	BC Transmission Corporation	Gordon Rawlings	Abstain	
1	Beaches Energy Services	Joseph S. Stonecipher	Negative	View
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	View
1	CenterPoint Energy	Paul Rocha	Negative	
1	Central Maine Power Company	Brian Conroy		
1	City of Vero Beach	Randall McCamish	Negative	View
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	

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1	Cleco Power LLC	Danny McDaniel	Negative	
1	Commonwealth Edison Co.	Daniel Brotzman		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	View
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	E.ON U.S.	Larry Monday		
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Abstain	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Abstain	
1	GDS Associates, Inc.	Claudiu Cadar	Abstain	
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	JEA	Ted E Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stan T. Rzad	Negative	View
1	Lake Worth Utilities	Walt Gill	Negative	View
1	Lakeland Electric	Larry E Watt	Affirmative	

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1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Negative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	Metropolitan Water District of Southern California	Ernest Hahn	Abstain	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	National Grid	Saurabh Saksena	Abstain	
1	Nebraska Public Power District	Richard L. Koch	Abstain	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Henry G. Masti		
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Negative	View
1	Omaha Public Power District	Douglas G Peterchuck	Affirmative	
1	Oncor Electric Delivery	Michael T. Quinn	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson		
1	Pacific Gas and Electric Company	Chifong L. Thomas		
1	PacifiCorp	Mark Sampson		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Affirmative	

1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Chelan County	Chad Bowman	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	South Texas Electric Cooperative	Richard McLeon	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson		
1	Southern Illinois Power Coop.	William G. Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Keith V Carman	Affirmative	View
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		

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2	Alberta Electric System Operator	Mark B Thompson	Abstain	View
2	BC Transmission Corporation	Faramarz Amjadi		
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning		
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	Midwest ISO, Inc.	Jason L Marshall	Abstain	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe		
2	Southwest Power Pool	Charles H Yeung		
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	American Electric Power	Raj Rana		
3	APS	Steven Norris	Abstain	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blue Ridge Power Agency	Duane S Dahlquist	Negative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Negative	
3	City of Clewiston	Lynne Mila	Negative	
3	City of Green Cove Springs	Gregg R Griffin	Abstain	
3	City of Leesburg	Phil Janik	Negative	
3	Cleco Utility Group	Bryan Y Harper	Negative	
3	ComEd	Bruce Krawczyk	Affirmative	

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3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Constellation Energy	Carolyn Ingersoll	Affirmative	
3	Consumers Energy	David A. Lapinski	Negative	View
3	Consumers Power Inc.	Roman Gillen		
3	Cowlitz County PUD	Russell A Noble	Negative	View
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Abstain	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons		
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier		
3	Hydro One Networks, Inc.	Michael D. Penstone		
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory David Woessner	Negative	
3	Lakeland Electric	Mace Hunter	Affirmative	View
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Los Angeles Department of Water &	Kenneth Silver		

	Power			
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Negative	
3	MEAG Power	Steven Grego	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Abstain	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	Ocala Electric Utility	David T. Anderson	Negative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Abstain	
3	OTP Wholesale Marketing	Bradley Tollerson		
3	PacifiCorp	John Apperson	Abstain	
3	PECO Energy an Exelon Co.	Vincent J. Catania		
3	Platte River Power Authority	Terry L Baker	Negative	
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Abstain	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salmon River Electric Cooperative	Ken Dizes		

3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson	Affirmative	
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young		
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Springfield Utility Board	Jeff Nelson	Abstain	
3	Tampa Electric Co.	Ronald L Donahey		
3	Turlock Irrigation District	Casey Hashimoto		
3	Umatilla Electric Cooperative	Steve Eldrige		
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	American Municipal Power - Ohio	Kevin Koloini		
4	American Public Power Association	Allen Mosher	Abstain	
4	City of Clewiston	Kevin McCarthy	Negative	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Negative	
4	Consumers Energy	David Frank Ronk		
4	Cowlitz County PUD	Rick Syring	Negative	View
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards	Abstain	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke	Affirmative	

4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	View
5	Chelan County Public Utility District #1	John Yale	Abstain	
5	City of Grand Island	Jeff Mead	Abstain	
5	City of Tallahassee	Alan Gale	Abstain	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy	James B Lewis	Negative	View
5	Cowlitz County PUD	Bob Essex	Negative	View
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Robert Smith		
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	

5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Cynthia E Sulzer		
5	JEA	Donald Gilbert		
5	Kansas City Power & Light Co.	Scott Heidtbrink	Negative	
5	Kissimmee Utility Authority	Mike Blough		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin		
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	Michael K Wilkerson		
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	
5	Otter Tail Power Company	Stacie Hebert		
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	
5	PPL Generation LLC	Mark A Heimbach		
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	Public Service Enterprise Group Incorporated	Dominick Grasso	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	

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5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	South California Edison Company	Ahmad Sanati		
5	South Carolina Electric & Gas Co.	Richard Jones		
5	South Mississippi Electric Power Association	Jerry W Johnson		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.		
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	View
6	Cleco Power LLC	Matthew D Cripps	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	View
6	Constellation Energy Commodities Group	Brenda Powell		
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View
6	Florida Municipal Power Pool	Thomas E Washburn	Negative	View

6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Thomas Saitta	Negative	View
6	Lakeland Electric	Paul Shipps	Negative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Louisville Gas and Electric Co.	Daryn Barker		
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	OTP Wholesale Marketing	Bruce Glorvigen		
6	PacifiCorp	Gregory D Maxfield		
6	Progress Energy	James Eckelkamp	Affirmative	View
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	RRI Energy	Trent Carlson		
6	Salt River Project	Mike Hummel		
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Western Area Power Administration - UGP Marketing	John Stonebarger		
6	Xcel Energy, Inc.	David F. Lemmons		
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner	Affirmative	

8	JDRJC Associates	Jim D. Cyrulewski		
8	Pacific Northwest Generating Cooperative	Margaret Ryan	Abstain	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Abstain	
9	California Energy Commission	William Mitchell Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	Oregon Public Utility Commission	Jerome Murray	Affirmative	
9	Public Service Commission of South Carolina	Philip Riley	Affirmative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Midwest Reliability Organization	Dan R Schoenecker		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	View
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	View
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Southwest Power Pool Regional Entity	Stacy Dochoda		
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

Individual or group. (41 Responses)
Name (27 Responses)
Organization (27 Responses)
Group Name (14 Responses)
Lead Contact (14 Responses)
Contact Organization (14 Responses)
Question 1 (40 Responses)
Question 1 Comments (41 Responses)
Question 2 (40 Responses)
Question 2 Comments (41 Responses)
Question 3 (40 Responses)
Question 3 Comments (41 Responses)
Question 4 (40 Responses)
Question 4 Comments (41 Responses)
Question 5 (40 Responses)
Question 5 Comments (41 Responses)

-	-
	Individual
	Jennifer Wright
	SDG&E
	Yes
	Yes
	Yes
	Yes
	Yes
	Individual
	JAMES SMITH
	ASSET MANAGEMENET
	Yes
	Yes
	Yes
	Yes
	Yes
	Individual
	Si Truc PHAN
	Hydro-Quebec TransEnergie (NCR07112)

	Yes
	Yes
	Yes
	Yes
	No
	The minimum frequency of Vegetation Inspection should be based upon an average growth rates of smaller regions than all North America. Example, above the latitude of about 50 degrees North, the vegetation growth rates is limited. We think that Vegetation Inspection frequency should be relaxed to 3 years for those areas in Canada. As indicator of the minimum frequency requested in R6, we suggest to use a global vegetation index like the Normalized Difference Vegetation Index (NDVI). The NDVI has been in use for many years to measure the vigor of vegetation growth among other things. http://earthobservatory.nasa.gov/Features/MeasuringVegetation/
	Individual
	Michael Gammon
	Kansas City Power & Light
	Yes
	No
	These proposed Requirements, Measures and Violation Severity Levels as written do not give credit to the Transmission Owners for effectively monitoring their systems and taking appropriate actions in regard to vegetation clearing. Why does it make sense to punish and penalize a Transmission Owner for discovering an encroachment when they take the appropriate actions to remedy the condition before any facility outage occurs that results in compromising the reliability of the Bulk Electric System? These Requirements, Measures and VSL's should recognize the good practices of effective response to a vegetation condition and penalize ineffective response. Recommend the SDT consider including appropriate language to recognize effective remedial actions by Transmission Owners and by doing so, recognize effective efforts instead of punishing them. In addition, proving encroachments have not occurred will pose audit challenges in determining that encroachments have not occurred for the Auditors as well as Registered Entities. If no encroachments occur, then there is nothing to report or record. This is a weak platform to stand compliance on. Facility interruption events caused by vegetation contacts is definitively measurable and recordable. Recommend the SDT reconsider the concept of compliance with FAC-003 on the basis of sustained outages and remove the references regarding encroachments only. Recommend the SDT remove the LOWER VSL language from Requirements R1 and R2 and revise the Requirements and Measures to reflect the same.
	Yes
	Yes
	No
	1) R7 states "Each Transmission Owner shall complete 100% of its annual vegetation work plan...". We suggest to be consistent with all other sections of the rule that it should read, "Each Transmission Owner shall complete 100% of its annual vegetation work plan for all applicable lines...". Otherwise, leaves room for interpretation to include all lines including those not defined as applicable. Also require these same revisions to row R7 of the table "Time Horizons, Violation Risk Factors, and Violation Severity Levels". 2) In the "Additional Compliance Information" section Categories 1, 2, and 4 are each defined to have an A & B component to recognize the severity level difference for "applicable transmission lines" identified versus not identified "as an element of an IROL or Major WECC Transfer Path". However, Category 3 does not separate these two scenarios however it appears that the same distinction should apply. Additional comments: Vegetation Inspection Definition Recommend the SDT consider removing the conditional language, "that are likely to pose a hazard to the line(s) prior to the next". Vegetation inspections are not dependent on a predisposed condition of vegetation. Suggest the SDT remove that phrase and consider the following definition: The systematic examination of vegetation conditions on a maintained transmission line Right-of-Way under the Transmission Owner's control under a planned maintenance or inspection which may be combined with a general line inspection.

Individual
Joe Petaski
Manitoba Hydro
Yes
Yes
Yes
Yes
Yes
Group
SERC Vegetation Management sub-committee
Joe Spencer
SERC Reliability Corporation
No
We agree with the proposed definition as a replacement for active transmission ROW, however, in a review of NERC standards, the term ROW is not used except in FAC-003. It is therefore recommended that the term be removed from the NERC glossary.
Yes
Yes
Yes
Yes
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
Arizona Public Service Company
Yes
No
This is a reliability standard and the TO should know what its clearance needs are at all rated conditions, especially considering today’s technology. If the TO manages to this standard there is no need for R1 and R2.
No
The TO should be managing for reliability. The system is not static, like vegetation it moves and changes over time and that fluctuation should be taken into account to maintain reliability at all rated conditions.
No
The TVMP shall demonstrate the TO’s ability to manage the system at all rated conditions to maintain reliability.
Yes
Individual

	Weston Davis
	Central Maine Power Company - IberdrolaUSA
	No
	The definition does not define transmission owner responsibility for areas covered by “danger tree” rights. This area is outside the maintained width but for economic and social reasons the transmission owner can not remove all danger trees. Utilities have procedures in place to remove the hazard trees but it is not practical to remove all danger trees that have the potential to violate the MVCD should they fail. This area of the definition requires clarification.
	Yes
	Yes
	Yes
	Yes
	Group
	Hydro One Networks
	Sasa Maljukan
	Hydro One Networks Inc.
	No
	The revised definition of ROW is unclear in regards to the application of standards and/or historic records as a means of determining ROW width; is it necessary for a TO to select one method to apply in all cases, or can each span be treated in the manner deemed most appropriate by the TO? Additionally “blowout Standard” has not been defined in the document or in the technical paper, and therefore it is not clear exactly how this method would be applied, and subsequently defended under scrutiny.
	Yes
	Yes
	Yes
	Yes
	Group
	Salt River Project
	Cynthia Oder
	Cynthia Oder
	Yes
	Yes
	Yes
	Yes
	Yes

	Individual
	Gordon Rawlings
	BC Hydro
	Yes
	Yes
	Yes
	Yes
	You could also include the term “maintenance standards”.
	Yes
	You could also include other documentation such as monthly financial and program variance reports. Additional Comments Table 1: R6 definitions could be clearer. Suggested clarification: VSL Lower – Greater than 95% of annual inspections complete but less than 100% complete. VSL Moderate – Greater than 90 % of annual inspections complete but less than 95% complete VSL High – Greater than 85% of annual inspections complete but less than 90% complete VSL Severe – Less than 85% of annual inspections completed Table 1 R7 definitions could be clearer. Suggested clarification: VSL Lower – Greater than 95% of annual work plan complete but less than 100% complete. VSL Moderate – Greater than 90 % of annual work plan complete but less than 95% complete VSL High – Greater than 85% of annual work plan complete but less than 90% complete VSL Severe – Less than 85% of annual work plan completed Table 2: This table includes a number of common nominal system voltages vs MVCD distances by altitude. However, some utilities have other non-standard voltages, in our case 287 kV, which forms a significant part of their system. It may be worthwhile for the standard to state what a utility should follow when a standard voltage class is not present – i.e. go to the next higher voltage MVCD if a particular voltage isn’t in the table, or direct the utility to do its own Gallett Equation calcuations for their unique voltage class. Otherwise, different utilities may create a non-standard solution that wouldn’t address the risk.
	Group
	Northeast Power Coordinating Council
	Guy Zito
	Northeast Power Coordinating Council
	No
	There was no definition of ROW listed in FAC-003-1. The revised definition of ROW in FAC-003-2 is unclear regarding the application of standards and/or historic records as a means of determining ROW width. Is it necessary for a TO to select one method to apply in all cases, or can each span be treated in the manner deemed most appropriate by the TO? “Blowout standard” has not been defined in the document, technical paper, or NERC Glossary and it is not clear what this method is, and exactly how it would be applied. It could not be defended under scrutiny. It is still unclear whether Danger Tree rights are included in this definition. In the NERC Glossary of Terms, Right-of-Way (ROW) is defined as “A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.” Propose keeping this definition. Is encroachment into the MVCD, or (MVCD plus additional distance as defined by the TO)? MVCD, as specified within the body of FAC-003-2 "is a calculated minimum distance stated in feet (meters) to prevent flashover between conductors and vegetation, for various altitudes and operating voltages." MVCD should be “formally” defined in this document, and the NERC Glossary. Can a list/database be established in 2011 that lists the widths for the pre-2007 vegetation management records?
	Yes
	Yes
	Yes
	No
	There is no percentage language in M7. Is it R7 that is being referred to?

	Individual
	Andrew Pusztai
	American Transmission Company, LLC
	Yes
	Yes
	Yes
	Yes
	Yes
	Individual
	Thad Ness
	American Electric Power
	Yes
	No
	American Electric Power believes that the phrase "arboricultural activities or horticultural or agricultural activities" was mistakenly introduced into Footnotes 2 and 4, and should be deleted from both footnotes. If the phrase remains in the Standard, it may empower orchard growers, landowners and others to plant trees on the right of way and challenge Transmission Owners' rights to perform maintenance on the presumption that the standard will exempt the TO from violating the outage or encroachment requirements.
	No
	For increased clarity, AEP offers the following change to the second paragraph of M1, as well as the second paragraph of M2. The original text “If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation” should be replaced with ““If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation growing into or blowing together with the conductor within the ROW, this shall be considered the equivalent of a Real-time observation. A brief encroachment caused by falling vegetation passing through the MVCD is not considered an encroachment in this requirement”.
	Yes
	Yes
	Individual
	William Rees
	Baltimore Gas and Electric Co.
	Yes
	Yes
	No
	M1 & M2 bullet: “Real-time observation of any MVCD encroachments.” implies that real-time observation of vegetation encroachment ensures reliable operation the Bulk Electric System. The reliability standard objective states; “To improve the reliability of the electric Transmission system by preventing those vegetation related outages that could lead to Cascading.” However, real time observation of current operating conditions provides no assurance that vegetation will not lead to outages since it doesn’t take into consideration the full conductor range of

	motion including maximum sag. BGE recommends removing the language. If an inspector finds vegetation encroaching into the MVCD during a visual inspection he / she should immediately initiate an Immediate Threat Notification. Therefore, this measure has no value.
	Yes
	Yes
	Individual
	Jason Regg
	TVA
	No
	I suggest that "arboricultural activities or horticultural or agricultural activities be removed and changed to installation, removal or digging of vegetation.
	Yes
	Yes
	Yes
	No
	I suggest that footnote 4 be changed by removing the reference to arbicultural, horticultural or agricultural activities.
	Individual
	Michael Schiavone
	Niagara Mohawk Power Corporation (dba National Grid)
	No
	It is still unclear whether Danger Tree rights are included in this definition. Additional question: Can we establish a list/database in 2011 stating the widths for the pre-2007 vegetation management records? There is no definition of ROW listed in FAC-003-1, however in the NERC Glossary of Terms, Right-of-Way (ROW) is defined as “A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.” We propose keeping this definition.
	Yes
	Yes
	Yes
	No
	There is currently no percentage language in M7. If they are referring to R7, then YES it is adequate.
	Individual
	Michael Pakeltis
	CenterPoint Energy
	No
	CenterPoint Energy agrees with the removal of “Active Transmission Line ROW” as a defined term. The change in the NERC Glossary definition for Right-of-Way (ROW) alone, however, does not address all of the remaining interpretation issues within the Standard that still exist. The following issues still require resolution: 1. The “force majeure” was moved from the Applicability section to a footnote, and is no longer an encompassing exception for each Requirement. Therefore, the “force majeure” footnote needs to be applied not only to R1, R2, R6, and R7 but also R4 and R5. For R4, notification to the control center would likely be restricted during a natural disaster. For R5, correction action by the control center may not be possible during a natural disaster. 2. The exception for

	applicability beyond the "Rating and all Rated Electrical Operating Conditions" should be included not only in R1, R2, and R3, but also R5 and R7. For R5 and R7, the encroachment into the MVCD should consider whether the line is operating within its design limits. 3. The use of the term "Fault" in M1 and M2 should be revised to "Sustained Outage". A "Fault" can be associated with a Momentary Outage or a Sustained Outage. The scope of R1 and R2 is specific to Sustained Outages only. The Periodic Data Submittal is specific to Sustained Outages only as well. If a later confirmation of a "Fault" by the Transmission Owner indicates that a vegetation encroachment into the MVCD was due to a fall-in from inside the ROW, yet caused only a Momentary Outage, the Transmission Owner would be in violation of R1 because M1 considers it to be the equivalent of a Real-time observation. The current scope of the Standard is not intended to include Momentary Outages. If it was, the Periodic Data Submittal would capture this type of outage, which it does not. 4. In the Introduction Section 5 - Background, fall-ins are characterized as "statistically intermittent" and "these types of events are highly unlikely to cause large-scale grid failures". CenterPoint Energy agrees and therefore recommends that fall-ins be excluded from the Requirements R1, R2, and Periodic Data Submittal of outages. This would negate the need for determining the limits of the ROW, thus simplifying the Standard to a great margin while not sacrificing the emphasis of the Standard. The Draft 5 Background Information states the criteria for developing a results-based reliability standard such that "each requirement should identify a clear and measurable expected outcome." When the determination of the limits of the ROW goes beyond the interpretation of the legal limits of the ROW, it adds a level of complexity that may be unclear and not deterministically measurable. 5. For R6, CenterPoint Energy believes the detailed rationale and studies used for the determination of the required one year inspection cycle should be included in the Guidelines and Technical Basis. The explanation provided in the Rationale that it is "based upon average growth rates across North America and on common utility practice" are unfounded and arbitrary without a specific reference to a North American study. 6. R7 contains the phrase, "provided they do not put the transmission system at risk of a vegetation encroachment". CenterPoint Energy recommends this phrase be replaced with the more specific terminology used in the Rationale for R7 and R3: "provided they do not allow encroachment of vegetation into the MVCD." 7. CenterPoint Energy believes the Periodic Data Submittal should be clarified as to the specific conditions under which Sustained Outages are reported. There is a reference to footnote 2 regarding the exclusion for the "force majeure"; however, the exclusion for lines operating outside their design limits as mentioned in R1, R2, and R3 is missing. CenterPoint Energy believes the wording should be changed to include all applicable exclusions for added clarity and recommends the following wording: "The Transmission Owner will submit a quarterly report to its Regional Entity, or Regional Entity's designee, identifying all Sustained Outages of applicable transmission lines operating within their Facility Rating and all Rated Electrical Operating Conditions as determined by the Transmission Owner to have been caused by vegetation, except as excluded in footnote 2, which includes as a minimum, the following:" 8. The Guidelines and Technical Basis and the Technical Reference with the Gallet Equation should be combined into one document as a supplement to the Standard to avoid duplication in wording and misinterpretation of context. 9. The Guideline and Technical Basis under Requirement R6 refers to the "percentage of the required ROW inspections completed" and should be revised to match the wording of R6 and the VSL for R6 as the "percentage of applicable transmission line inspections completed." 10. CenterPoint Energy agrees that the Rationale test boxes should be deleted from the Standard and applicable explanatory text be included within the Guidelines and Technical Basis. 11. The Guidelines and Technical Basis should contain specific examples for determining if a fall-in is considered inside or outside the ROW. 12. CenterPoint Energy recommends modifying the Technical Reference section regarding "Selecting a Maintenance Approach" to delete the sentences beginning with, "If constraints cannot be overcome and if design clearances are sufficient…" and continuing through to, "identified early for rectification." This example may lead the public to inappropriately ask the utilities for exceptions to allow vegetation beneath the transmission lines, and it also does not address the dynamics of future modifications to the transmission lines (e.g. higher operating temperatures or new conductors) that may necessitate reduced clearances to ground, thus requiring removal of now mature vegetation. The example should not be included in a Standard intended to reduce vegetation risks to the transmission system. It is also in conflict with later statements in the Technical Reference regarding Set Objectives which emphasize maintaining access and clear lines of sight. 13. In general, CenterPoint Energy strongly believes the proposed FAC-003-2 has gone far beyond what was contemplated by the Commission in FERC Order 693. The Commission's determination dealt with the following areas: (1) applicability; (2) inspection cycles; and (3) minimum clearances on National Forest Service lands. For instance, in Paragraph 729, the Commission states, "As proposed in the NOPR, the Commission approves Reliability Standard FAC-003-1 with no proposed modification on the issue of clearances. The Commission reaffirms its interpretation that FAC-003-1 requires sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions…." Rewriting the minimum clearances introduces a new set of confusing definitions, and further burdens the Transmission Owners with new documentation requirements while providing little, if any, benefit when compared to the Clearance 2 concept in the existing Standard. A preferred approach would be to incorporate the following few items into the existing Standard FAC-003-1: (1) the RC versus the RRO; (2) the designation of a specific inspection frequency; (3) the Gallet equation; and (4) the applicability to National Forest Service lands.
	Yes
	Yes

	Yes
	No
	CenterPoint Energy could not find any reference to an example percentage complete calculation for the annual work plan in the Standard for M7, in the Guideline and Technical Basis for M7, nor in the Technical Reference for M7. There was such an example for M6 which was helpful. CenterPoint Energy recommends such an example be included for M7.
	Individual
	Greg Rowland
	Duke Energy
	Yes
	Yes
	We agree with the drafting team's approach, and also agree with reinstating reporting of Category 3 (Fall-ins from outside the ROW) in the Additional Compliance Information section. The SDT responded to comments submitted with the last ballot that: "Zero tolerance for vegetation caused outages is a stated goal of FERC and NERC as it relates to this standard. This policy is part of FAC-003-1 and in concept did not change with the proposed version. The SDT recognizes this concern and has developed gradation taking into account line criticality in VRF's and type of outage not contained in the current version FAC-003-1. Finally, it is also important to note that each and every incident or potential violation is investigated and addressed based on the specific circumstances surrounding the particular event. These investigations should necessarily take into consideration and recognize the utility's individual efforts in responding to an encroachment situation." In addition, we believe that clarifying changes need to be made to footnotes 2 and 4. Clarify footnote 2 by removing the phrase "arboricultural activities or horticultural or agricultural activities" and replacing it with the phrase "installation of". Similarly, clarify footnote 4 by removing the phrase "arboricultural, horticultural or agricultural activities", and replacing it with the phrase "or human activities such as installation, or removal or digging of vegetation."
	Yes
	However, this change was not completely made in paragraph five of the Guideline and Technical Basis document. There the phrase "an investigation" should be replaced by the phrase "a later confirmation"
	Yes
	Yes
	Group
	Platte River Power Authority Substation Maintenance Group
	Deborah Schaneman
	Platte River Power Authority
	No
	We agree that the ROW width in no case exceeds the TO's legal rights but may be less. We do not agree that the revised NERC Glossary definition for Right-of-Way addresses paragraph 734 of FERC Order 693 "that rights-of-way be defined to encompass the required clearance areas instead of the corresponding legal rights, and that the standards should not require clearing the entire right-of-way when the required clearance for an existing line does not take up the entire right-of-way". The engineering or construction standards for establishing the width of the corridor outlined in the definition are in most cases not useful. We will continue to rely on our easements and legal rights with this definition. We believe the Active Transmission Line ROW definition in the previous version more clearly addressed paragraph 734 of FERC Order 693.
	Yes
	Yes
	Yes

	Yes
	Individual
	RoLynda Shumpert
	South Carolina Electric and Gas
	Yes
	Yes
	Yes
	Yes
	Yes
	Group
	Bonneville Power Administration
	Denise Koehn
	BPA, Transmission Reliability Program
	Yes
	Yes
	BPA prefers the stratified levels of violation severity presented in the table for R1 and R2. Foot note #2 on page 8 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. What specifically does this phrase refer to? Foot note #4 on page 12 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. What specifically does this phrase refer to?
	Yes
	Yes
	The TO procedures / policies and specifications shall demonstrate the TO's ability to manage the system at all rated conditions to maintain reliability. BPA believes that the intent is clear, but the fundamental approach of using the MVCD (table 2) to manage a vegetation program is still problematic. These values are flashover distances and are way too close. This is acknowledged in a footnote to table 2 but no identification of allowable buffers/distances between energized phase conductors at rated temperatures and vegetation is discussed (this is left up the transmission owners). Clarity is needed on this topic. Setting a finite distance limit based on recognized standards, good science and risk avoidance should be done for the industry. BPA previously made this comment during the drafting of the standard. It was not addressed then, nor has it been addressed now.
	Yes
	Group
	Tampa Electric Company
	Luke Diruzza
	Tampa Electric Company
	Yes
	This provides a more flexible definition than previous drafts.
	Yes
	Adds clarity to the VSL from an audit perspective, this is an improved description to the Standard.

	Yes
	Confirmation allows for the potential of a greater number of “action items” than just investigation.
	Yes
	Good addition, adds clarity and improves overall understanding of the requirement.
	Yes
	This allows flexibility for the T.O. to determine the type of “unit” used in calculating the percentage complete.
	Group
	NextEra Energy
	Silvia Parada Mitchell
	Corporate Compliance
	Yes
	Yes
	Although NextEra Energy Inc. (NextEra), including Florida Power & Light Company, agrees with the changes referenced for R1 and R2, NextEra is concerned that the exemptions identified in footnote 2 for “…arboricultural activities or horticultural or agricultural activities…,” and similar language in footnote 4, are too broad. For example, this language appears to include an exemption for a landowner, who, during arboricultural activities or horticultural or agricultural activities, causes a vegetation contact with a transmission line (e.g., cutting or lifting a tree into a transmission line). This places the Transmission Owner in the difficult position of a landowner arguing it is exempt from a controllable risk. Thus, the “…arboricultural activities or horticultural or agricultural activities…” references should be removed from footnote 2, and the similar language in footnote 4
	Yes
	Yes
	Yes
	Individual
	Darryl Curtis
	Oncor Electric Delivery Company LLC
	Yes
	Yes
	Yes
	Yes
	Yes
	Individual
	Kirit Shah
	Ameren
	Yes
	Yes
	This is more in alignment with a results-based reliability standard.

	Yes
	Yes
	This clearly defines “intent”.
	Yes
	This is directed toward R7 rather than M7.
	Individual
	Amy Kupferberg
	Individual
	My Comments do not relate to the question asked, however, I saw no other place to add my comment. I would like to thank NERC for allowing the public to participate in the process of improving the reliability standard FAC-003-1. I became interested in Vegetation Management requirements for Transmission Lines, after Con Edison clear cut the ROW behind my home. I appreciate the importance of safe and reliable electrical service, and recognize how an effective TVMP contributes to this goal. In this whole process, what has dispirited me the most, is the inaccurate information being conveyed about why the clear cutting was necessary and, the causes of the August 14th, 2003 blackout. The narrative goes something like..”a tree falling onto transmission lines caused the black out of 2003.” I find it harmful because it misdirects the focus from the grid’s short fallings, and impedes upgrading the system to improve reliability. I found this same philosophy in the initial pages of CN Utility’s document, UTILITY VEGETATION MANAGEMENT FINAL REPORT MARCH 2004. It suggests that had the trees been adequately maintained, the blackout would have most “likely” not happened. Now I am aware of the qualification of the word “likely,” but the document is heavily weighted on the contribution of tree contact to the blackout. We know that de-regulation and the physical nature of A.C. current had more to do with the causes of the blackout, than tree contact. The timeline shows a range of cascading system failures that created the catastrophic event. The trouble began at 1:58 p.m. when First Energy generating plant in Eastlake, Ohio, shuts down. At 3:06 p.m. a First Energy 345-kV transmission line fails. As a result, at 3:17 p.m voltage dips temporarily on the Ohio portion of the grid. Controllers take no action, but power shifted onto another power line, overloading it and, causing it to sag into a tree and go offline at 3:32 p.m. Mid West ISO and First Energy controllers fail to inform system controllers in nearby states. At 3:41 and 3:46 p.m., two breakers connecting First Energy□s grid with American Electric Power are tripped. 4:05 p.m., a sustained power surge on some Ohio lines signals more trouble building. At 4:09:02 p.m., voltage sags deeply, as Ohio draws 2 GW of power from Michigan. 4:10:34 p.m., many transmission lines trip out, beginning in Michigan and then in Ohio, blocking the eastward flow of power. Generators go down, creating a huge power deficit, in seconds, power surges out of the East, tripping East coast generators, and the rest is history. The U.S.-Canada Power System Outage Task Force: Final Report on Implementation of Recommendations, September 2006, states that “Inadequate reactive supply was a factor in most of the events.” and “the assumed contribution of dynamic reactive output of system generators was greater than the generators actually produced, resulting in more significant voltage problems.” The backup generators were not adequate to handle the amperage load or voltage needed. A lack of coordination of System Protection Programs(relays tripping), inadequate communication between Utilities/TOs, and lack of "training of operating personnel in dealing with severe system disturbances" are all the causes for the blackout. With respect to vegetation management, the findings from The U.S.-Canada Power System Outage Task Force: Final Report on Implementation of Recommendations, September 2006, clearly did not intend for transmission owners to develop a one-size-fits-all standard. The Energy Policy Act of 2005, initiated NERC to draft and adopt the standard FAC-003-1. When I read through the standard, it all seems very reasonable. I can understand the stiff penalties for noncompliance because it seems, like an easy fix, compared to the necessary, major changes in infrastructure. The principles further outlined in ANSI A300 VII, and “Best Practices” IVM, seem very reasonable too. There is mention of the environment, property owners, even proper pruning techniques. The wire zone clearance of 10 feet and, allowing low growing compatible vegetation in the boarder zone, seems to retain more vegetation, than remove. However, in practice, the TOs are simply clear cutting the ROW, with no regard for the enviroment, the trees that they are cutting, or the abutting properties. It took Con Edison 2 1/2 half days to clear 450 tress form behind our home. We are now forced to see and hear 93,000 cars a day from the Sprain Parkway. Following the clearing, our real estate broker dropped the asking price by 30%. The house remains empty and unsold. Apparently, no one is interested in spending 32,000K a year in property taxes to look at transmission towers/lines and live on a highway. This has been devastating to our family, and thousands of others in Westchester County. They removed a buffer of trees that were 150 feet away from wires and towers, on a downward slope. These trees would have never made contact with conductors. Con Edison’s defense is that they did it because it was in their right to. Moreover, they use the NERC fine structure to defend their behavior. I went through the Notice of Penalties that NERC has issued from 6/2/08-2/01/11. Out of 646 Notice of Penalties, 1700 violations were sited, 36 out of 1700 penalties were issued for violations to the FAC- 003-1 standard. Some NOPs had multiple violations-18 R1 violations were cited and 29 penalties were issued for R2 violations. Out of the 29 R2 penalties, 20 involved tree contact. Some outages were caused by sagging wires, some were caused by arcing electricity looking for a ground fault, but none were caused by a tree falling onto the transmissions wires. The numbers should put into perspective how immaterial the problem of tree contact really is. Think about it... 20 out of

	1700 involved tree contact, and none of then resulted in a sustained outage. That means 1680 violations were issued due to other system failures. To use these penalties as an excuse is a complete over exaggeration. What is missing from the standard and the fine structure, are penalties for over cutting and violations to other stipulations, such as proper communication, training, and aftercare of the affected areas. The problems that have arisen from current TVMP activities being executed nationally on our ROWs, is not a public perception problem. Rather, TOs are not complying with standards that are meant protect the environment and they are not respecting the property rights of the neighboring homeowners. I appreciate the opportunity to share my views, and would take any opportunity to further participate in protecting the rights of property owners, and the environment, while working to secure safe and reliable electrical service. Most respectfully, Amy M Kupferberg Utility Whisperer
	Individual
	George Czerniewski
	Consolidated Edison Company of New York, Inc. - Transmission Line Maintenance
	Yes
	Yes
	Yes
	Yes
	Yes
	The added language for the annual work plan percentage complete calculation is shown in R7 not M7 as stated in the question. In the Guideline and Technical Basis Section for Requirement R6, there is a sample calculation shown for the amount of lines the TO failed to inspect. An example should also be included for Requirement R7 since there is some confusion regarding how modifications to the work plan affect the calculation. In the Lower VSL column for R7, it states that the TO failed to complete up to 5% of its annual vegetation work plan (including modifications if any). If a TO operates 100 lines and submits a justified modification that affects 10 miles of lines, the total number of units in the final amended plan is 90 miles. When you read the VSL, it is somewhat confusing since the information in parenthesis says that the calculation 'includes' the modifications. Should it state 'excludes modifications if any' or the VSLs can simply be re-written to state that ..The TO failed to complete up to x% of the final amended plan.' Also, the VSLs in R6 and R7 should be consistent with each other: R6 says '...TO failed to inspect 5% or less.....' and R7 says '...TO failed to complete up to 5%....' They both should use the same verbiage in each VSL whether it is 'x% or less' or 'up to and including x%.'
	Individual
	andres lopez
	USACE
	Yes
	Yes
	Yes
	No
	Yes
	Individual

	CJ Ingersoll
	CECD
	Yes
	Yes
	No
	Suggested Modification to the Measure - "If an after-the-fact analysis of a Fault by the Transmission Owner determines that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of observing an encroachment in Real-Time." CECD would also like to comment on the Evidence Retention section, as it relates to Measures. The Evidence Retention section states that the Transmission Owner retains data or evidence to show compliance with Requirement R1, R2, R3, R5, and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years...." Measures provide examples of evidence that a Transmission Owner can produce to show compliance with the associated Requirement but are not separate Requirements to be managed so reference to Measures should be deleted from the Evidence Retention section of the standard.
	Yes
	Because Requirement 5 and 7 use the phrase annual work plan, and there is not a Requirement to develop a work plan, this Requirement should include a relationship between the document that is developed for maintenance strategies and the annual work plan.
	Yes
	Individual
	Edward J Davis
	Entergy Services, Inc
	Yes
	The revised Glossary definition of ROW helps to clarify the intent of what is expected and/or considered ROW stipulations. This is a beneficial addition/clarification.
	Yes
	Yes
	Yes
	Yes
	The actual clarifying language seems to have been added to R7 instead of M7 (as stated above). The clarifying language provides benefit as added to R7, and should remain in R7. Additionally, we feel that, in an effort to promote consistency with the other 6 Requirements, the term "on applicable Transmission lines" should be added at the end of the first sentence of R7, as it is listed in all other R's. The first sentence of R7 currently reads: "Each Transmission Owner shall complete 100% of its annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD". We feel the first sentence should read "Each Transmission Owner shall complete 100% of its annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD on applicable transmission lines".
	Individual
	David Burke
	Orange and Rockland Utilities, Inc.
	Yes
	Yes
	Yes

	Yes
	Yes
	The added language for the annual work plan percentage complete calculation is shown in R7 not M7 as stated in the question. In the Guideline and Technical Basis Section for Requirement R6, there is a sample calculation shown for the amount of lines the TO failed to inspect. An example should also be included for Requirement R7 since there is some confusion regarding how modifications to the work plan affect the calculation. In the Lower VSL column for R7, it states that the TO failed to complete up to 5% of its annual vegetation work plan (including modifications if any). If a TO operates 100 lines and submits a justified modification that affects 10 miles of lines, the total number of units in the final amended plan is 90 miles. When you read the VSL, it is somewhat confusing since the information in parenthesis says that the calculation 'includes' the modifications. Should it state 'excludes modifications if any' or the VSLs can simply be re-written to state that ..The TO failed to complete up to x% of the final amended plan.' Also, the VSLs in R6 and R7 should be consistent with each other: R6 says '...TO failed to inspect 5% or less.....' and R7 says '...TO failed to complete up to 5%....' They both should use the same verbiage in each VSL whether it is 'x% or less' or 'up to and including x%.'
	Group
	NERC Staff
	Doug Keegan
	NERC
	No
	NERC supports a revised definition and prefers the definition in Draft 5 over the Active Transmission Line ROW definition used in Draft 4. NERC believes the use of the term “pre-2007 vegetation maintenance records” in the proposed definition is ambiguous and will likely be interpreted differently throughout the industry. Therefore, NERC supports this change subject to removing the aforementioned term.
	No
	The sentence was added to the rationale but the phrase “in order of increasing severity” is not in the requirement or their associated VSLs. NERC staff does not support the language in the rationale box which differentiates the VSL based on skill level of maintenance personnel rather than the impact to reliability of the encroachment. The VSL should be based on whether or not the owner managed the vegetation to prevent encroachment and therefore be binary. See additional comments submitted separately regarding combining R1 and R2.
	No
	Concur with restating as mentioned above. Other issues remain regarding data reports indicating no sustained outages or real-time observations. These measures appear to indicate that if the outages or real-time observations are not documented then an encroachment didn’t occur. What will compel an entity to document these occurrences? In addition, the last two paragraphs of the Measure are not really measures. They would be better served as part of the Requirement.
	No
	Adding the term “maintenance strategies” is not helpful in the requirement. NERC staff recommends the following: “Each Transmission Owner shall have a documented vegetation management plan that includes maintenance strategies, procedures, processes, and specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that include(s) the following:”
	Yes
	Actually, R7 contains the clarifying language. It should be noted that although R7 indicates the TO shall complete 100% of the VM work plan, there is no requirement in this draft that a plan is actually developed.
	Individual
	Saurabh Saksena
	National Grid
	No
	The revised ROW definition emphasizes the ROW width needed to operate the transmission line(s). It is National Grid’s interpretation that the width established when the line was constructed is the width to be maintained. This width is documented in engineering drawings, per-2007 vegetation records or blow-out standards. This definition does not imply that danger tree rights beyond the constructed and maintained width are incorporated in the definition; therefore fallins - from outside the ROW but within within an area with danger tree rights would not be considered fallin-ins from within the ROW. National Grid would like the SDT to comment on this interpretation in its response to these comments.

Yes
Yes
Yes
No
There is currently no percentage language in M7. If they are referring to R7, then YES it is adequate.
Group
Pepco Holdings Inc and Affiliates
David Thorne
Pepco Holdings Inc
Yes
Yes
Yes
Yes
Yes
Group
FirstEnergy
Sam Ciccone
FirstEnergy Corp.
No
Although for the most part we agree with the changes to the definition of ROW, we suggest the following changes. 1. The last sentence of the definition states "The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria." We do not agree with the phrase "in no case exceeds the Transmission Owner's legal rights" because there could be instances where special permission has been granted by landowners to the TO. We suggest revising this statement to "The ROW width may be less than the Transmission Owner’s granted rights based on the aforementioned criteria." 2. Regarding the phrase "blowout standard" used in the definition, we are assuming this is in reference to the company specific calculations for sag and sway on not on any one specific industry standard. We suggest clarification such as "Transmission Owner's specific blowout or sag and sway analysis in effect when the line was built".
No
For the Requirement R1 and R2 VSLs, we suggest that the proposed Moderate (fall-ins) and High (blowing together) VSL be interchanged. We believe that fall-ins are more severe encroachments than blowing together and the categories listed in the compliance section support this point. Category 1 (grow-ins) is most severe, followed by Category 2 & 3 (fall-ins) and Category 4 (blowing together).
Yes
Yes
Yes
Although we generally agree with Requirements R7 and its measure M7, we suggest adding clarifying wording to bullet 4 which states "Crew or contractor availability/ Mutual assistance agreements". In addition to availability, contractor performance may be another issue that requires modification to the work plan. We suggest adding

	another bullet that reads "Crew or contractor performance". The rationale behind this addition is to address poor safety, productivity and/or quality issues with a crew or contractor assigned to perform vegetation management. FirstEnergy provides the following additional comments and suggestions not related to the specific questions asked in this posting: 1. Requirement R5 – We appreciate this requirement which recognizes that the TO may face situations in which it is constrained from performing its vegetation management and are permitted to seek alternative methods. However, there may be instances where the TO has exhausted all course of action to perform vegetation and must utilize other means to prevent vegetation encroachment into the MVCD. Therefore, in these instances, "continued vegetation management" as stated in the requirement is not possible, but other methods such as line deratings and deenergizing of lines may have to be used. We ask that the phrase "to ensure continued vegetation management to prevent encroachments" be changed to read “to ensure continued reliability of the BES”. 2. Compliance Section – Category 3 – We suggest removing this category from the standard. Since fall-ins from outside the ROW are not considered a violation of this standard per Requirements R1 and R2, the entity should not have to report these fall-ins. 3. Objectives – We do not believe that is necessary for the Objectives statement to include the "defense-in-depth" concept which is actually an overarching goal of results-based standards in general and not specific to FAC-003-2. We suggest removing this phrase. 4. Background Section 5 – Similar to our comment above regarding defense-in-depth in the objectives statement, this is an overarching goal of results based standard and not specific to FAC-003-2. Therefore, we suggest removing the explanation of defense-in-depth from the background section. 5. Vegetation Inspection Definition – We suggest replacing the word "hazard" with "risk". 6. Requirement R4 – We do not agree with the phrase "without any intentional time delay" and suggest it be removed. This phrase is not measurable. Also, other drafting teams have attempted to incorporate this statement but industry comments have persuaded them to remove it; for example, the Reliability Coordination drafting team (Project 2006-06) initially proposed the same phrase but later removed it in their development of the COM/IRO standards. At the very least standards development should be consistent throughout the NERC standards drafting teams. We suggest the following as wording for Requirement R7: "Each Transmission Owner shall ensure the control center holding switching authority for the applicable transmission line is promptly notified when the Transmission Owner has confirmed the existence of a vegetation condition that can potentially cause a Fault."
	Individual
	Steve Rueckert
	Western Electricity Coordinating Council
	Yes
	Yes
	Yes
	Yes
	Yes
	We support the clarifying languae in M7 However, since there is no generic "Any other Comments" section associated with this on-line comment form, we raise a question here. On December 24, 2008, NERC issued an e-mail to all Transmission Owners in which it referenced its December 17, 2008 Public Notice – NERC Compliance Process #2008- 001, Vegetation-related Transmission Outage Reporting. The notice stated that: "Due to the potential severity of transmission outages caused by vegetation associated with Standard FAC-003-1, NERC is encouraging each Transmission Owner to self-report all Category 1 and Category 2 transmission outages related to vegetation to the Regional Entity within 48 hours utilizing the 48-hour vegetation reporting notice form provided by your appropriate Regional Entity." We do not see any reference to a 48-hour reporting notice in Ithis version of the standard. Is this still a requirement? The only reference to reporting is in the Additional Compliance Information section and references quarterly reporting only.
	Group
	Dominion Electric Market Policy
	Mike Garton
	Dominion Resources Services, Inc.
	Yes
	Yes

	Yes
	Yes
	No
	The red-line revision does not indicated changes to M7; therefore, Dominion is unable to evaluate the clarifying language identified in this question. If the SDT meant to reference R7, we agree that the clarification is adequate.
	Individual
	Jody Nelson
	Georgia Transmission Corp.
	Yes
	Yes
	Yes
	Yes
	Yes
	Group
	Southern Company Transmission
	JT Wood
	Southern Company Services
	Yes
	While we prefer the Active ROW definition, we are willing to accept the newly proposed definition.
	Yes
	No
	We would recommend the middle paragraph of M1 and M2 be revised as follows: "If a later confirmation of a Fault by the TO shows that vegetation encroachment within the MVCD has occurred from vegetation growing into or blowing into the conductor within the ROW, this shall be considered the equivalent of a Real-time observation. Brief encroachments caused by a falling tree going through the MVCD is not considered an encroachment."
	Yes
	Yes
	Individual
	T. Wiley
	Northern Indiana Public Service Company
	Yes
	No
	While there are some enhancements to the organization and content of the standard such as the addition of the Guidelines and Technical Basis section, clarification of what constitutes evidence of compliance, and tailoring of VSL severity levels for the requirements based on the risk each poses to the likelihood of contributing to a cascade.

	too many elements present in FAC-003-1 and which are vital to preventing vegetation caused outages and maximizing system reliability, have been eliminated from FAC-003-2. Specifically, the elimination of concrete, declared and audited clearance standards between vegetation and conductors (the existing Clearance 1 and Clearance 2 (R1.2)) Requirements) in the revised standard is a major defect that will decrease system reliability. It has been indispensable for NIPSCO when communicating with stake holders (governments, interest groups, land owners, the public, etc.) to point to these clearance standards to give credibility and support to the kind of tree removal and trimming that is necessary to achieve the stated objective of zero preventable tree caused outages. Without these declared clearance standards in the NERC standard, utility vegetation managers will constantly be challenged by stake holders to show them that such work is required rather than an elective choice on the utility's part. One of the key lessons learned from the 2003 blackout and First Energy's overgrown ROW tree problem was that individual land owners, local governments, and interest groups will exert pressure on the utility to only do the minimum amount of vegetation management. Without external and enforceable Vegetation Clearance Standards and by returning to a pre-2003 regime where the extent of vegetation clearing is left to the individual discretion and pressures at each utility, there is no doubt that tree clearance conditions will deteriorate over time and put system reliability at greater risk of vegetation contact.
	Yes
	No
	Yes

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

FAC-003-2 Vegetation Management Draft 5
NERC Staff Comments in Addition To Those Submitted On Comment Form
2.28.11

In addition to the comments NERC submitted to the five questions on the official comment form, NERC staff has numerous other comments to make with regard to this Draft 5. Before that, NERC staff first wants to acknowledge the significant effort and talent that the industry brought to attempt to improve upon Reliability Standard FAC-003-1 – Vegetation Management. This Draft 5 of FAC-003-2 – Vegetation Management entailed significant industry work towards understanding the issue, compromising on proposals and attempting to reach consensus utilizing the NERC Standards Development Process. While NERC staff believes this draft represents some improvements to the existing standard, it does not believe the draft in its totality represents an improvement to the existing standard. FERC Order 693 approved the existing Vegetation Management Standard and it provided a number of directives for NERC with regard to further developing the Standard in order to improve it. Such directives and NERC comments regarding how the directives were addressed included:

- FERC Directive - Develop compliance audit procedures, using relevant industry experts, which would identify appropriate inspection cycles based on local factors. The Commission is dissuaded from requiring the ERO to create a backstop inspection cycle at this time.

  NERC Comment – Compliance audit procedures are outside the scope of the SDT and this Draft 5. Although not required by the Commission, the SDT added an annual inspection cycle to the Standard, with a maximum of 18 months between inspections. NERC believes this requirement represents an improvement to the existing Standard and does not believe it is overly burdensome on utilities.

- FERC Directive - Remove the general limitation on lines 200kV and above to include lines that have an impact on reliability.
  - Do not reduce facilities included
  - Develop an acceptable definition for the applicability of this Reliability Standard that covers facilities that impact reliability while not unreasonably increasing the burden on transmission owners.
  - Evaluate the suggestions proposed by LPPC, APPA and Avista that regional entities should determine which facilities this standard applies to

  NERC Comment – NERC believes Draft 5 partially addresses this issue by increasing applicable facilities to IROL lines under 200kV. NERC staff is also concerned about

  - The possibility that this very addition could limit a regional entity's desire to include additional lines.

- The exclusion of facilities inside the fenced area of switching stations, stations and substations. These excluded areas still pose a vegetation related outage risk and the rationale for excluding them is not compelling enough.
- The separation of IROL (any voltage level) and non-IROL (200 kV and above) Transmission Lines into separate requirements with different VRFs. NERC believes all Transmission Lines subject to this standard should be under the same requirement and associated VRFs. IROL lines are relatively few and do not warrant their own requirement. By having lower VRFs for non-IROL lines, this version of the standard is weaker than the existing standard. These two requirements should be a single requirement with high VRFs

- FERC Directive - Develop a Reliability Standard that defines the minimum clearance needed as an improvement to IEEE 516 which FERC does not believe is appropriately used for purposes of reliability and/or safety.

  NERC Comment – Draft 5 makes a change from IEEE 516 and utilizes Gallet equations for industry clearances. While NERC believes these equations are technically accurate, NERC is concerned about the usefulness of the clearances determined under this methodology as put forth in this draft. NERC is not aware of any utility which would maintain clearances as specified in this draft as it has no built in safety factor. NERC is further concerned that utilities could be mandated by courts of law to reduce existing maintained clearances to values much closer to those determined by the methodology in this draft.

- FERC Directive - Define rights-of-way to encompass the required clearance areas instead of the corresponding legal rights, and the standards should not require clearing the entire right-of-way when the required clearance for an existing line does not take up the entire right-of-way.

  NERC Comment – NERC staff believes this directive was met and is addressed in question 1 of the comment form.

- FERC Directive – NERC should address the proposed modifications through its Reliability Standards development process.

  NERC Comment – NERC staff believes this directive was met in preparing this draft standard.

- FERC Directive - Collect outage data for transmission outages, analyze it, and use the results of this analysis and information in the development of the Reliability Standard.

  NERC Comment – NERC staff believes more work needs to be done in this area. NERC staff believes the drafting team should consider modifying the Periodic Data Submittal to include if outages occur on Federal land.

Other Draft 5 Issues

- Removal of a formal transmission vegetation management program, of Clearance 1 and of a documented vegetation management plan.

  NERC Comment – NERC does not support the removal of these items. NERC does not believe these changes represent an improvement to the standard and does not believe this existing requirement is overly burdensome to utilities. NERC does not understand why industry would not be willing to be held accountable to their vegetation management plans. NERC is concerned that the removal of these items could make it difficult for utilities to obtain permissions needed to maintain clearances between inspection cycles which are prudent for reliability and safety due to intervener or landowners exercising their rights and then pointing to this new standard as a the basis for smaller clearances. . Requirement 3 in this draft needs to include a documented plan and to clearly identify the specifics to be included in the plan and provide clarity of expectations. The SDT may not support such specifics as not being consistent with results-based standards development but NERC staff believes otherwise.

- Objectives**:** A qualifier in the standard Objective that it should apply to preventing the risk of vegetation related outages *that could lead to cascading outages.*

  NERC Comment – This qualifier limits the purpose of the standard, which should be to prevent vegetation related outages, not cascading outages. The more outages there are, the less the overall system reliability. An outage does not necessarily have to lead to a cascading outage to be significant and represent a reasonable risk to the BES. References to cascading outages should be removed.

- Background**:** This section excludes vegetations fall-ins and blow-ins from outside the ROW on the basis that they are not preventable.

  NERC Comment – Many fall-ins and blow-ins from outside the ROW are preventable. Trees outside the ROW must be managed adequately to prevent outages on the BES. The work to remove and/or prune trees outside the ROW may be more difficult and costly than such work inside the ROW, but that is not sufficient reason to exclude this work. In addition, utilities wishing to perform such work might be prevented from doing so by regulatory bodies based upon the lack of a specific requirement in this standard.

- Requirement 1 & 2: These requirements discuss preventing encroachments into the MVCD of an applicable line that is operating within its Rating.

  NERC Comments –NERC staff would like confirmation that "Rating" is intended to include all published ratings issued by the facility owner, such as Normal, Emergency, etc.

- Requirement 4: R4 states that "Each Transmission Owner, without any intentional time delay, shall notify…"

  NERC Comments: The previous version of the standard included a time limit of 15 minutes once communications became available. This should be reinstated.

- Requirement 7: R7 sets the requirement for each Transmission Owner to complete 100 percent of its annual vegetation work plan.

  NERC Comments – NERC is concerned that the draft doesn't have a requirement for a Transmission Owner to have a documented annual plan making Requirement 7 unenforceable. In addition, Requirement 7 has a number of other qualifiers that would seem to allow manipulation of the annual plan to ensure compliance.

- Draft 5 document quality

  NERC Comments – this draft has some typographical errors which need to be fixed. For example, on page 28, reference to use of Table 5 versus Table 7 based on knowledge of maximum transient over-voltage factor is reversed. These edits could probably be handled through a recirculation ballet.

- Previously raised NERC issues

  NERC Comments – NERC staff posted several comments on the Draft 4 version of this standard in July 2010. NERC believes most of the concerns it raised in those comments are not addressed in Draft 5 and continue to be a concern for NERC.
- General compliance and audit issues

  NERC Comments –

  - The whole "sustained outage" concept in R1 (for fall ins and blow ins) is unworkable from an enforcement perspective.
  - The difference between a violation and a non-violation in Draft 5 is whether the registered entity was fortunate with regard to an encroachment. This part should be rewritten to say that any tree contact is a violation. VRFs and VSLs could then be used to address whether the violation was minor or serious.
  - There could be a lot of litigation over whether "circumstances" were really "beyond the control" of the TO. NERC had previously objected to the implementation of a force majeure clause in the standard. If an entity failed to carry out its annual plan, that should be treated as a violation, and any excuses for failing to do so or for changing the plan mid-year all go to whether the penalty should be $0 or substantial.
  - For the evidence retention period, the entity really should retain evidence of compliance until the next compliance audit. Since some TOs may be on a 6 year audit schedule, the 3 year retention period is not sufficient.

Successive Ballot (February 18-28, 2011) Consideration of Comments Report

Project 2007-07 Vegetation Management — September 30, 2011

Summary Consideration:
In order to be consistent with the latest version of NERC's Results Based Standards template, the heading "Objective" was replaced with "Purpose," and the numbering, headings, and sections were reformatted as necessary.

Several entities expressed concern with the use of the Minimum Vegetation Clearance Distance (MVCD) and elimination of Clearance 1. With respect to comments about the MVCD, R3 does not suggest the MVCD be used as a distance to manage vegetation. The MVCD was established as a beginning of a series of "building blocks" for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions. R3 requires that a Transmission Owner consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this "building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD. In a performance-based standard, requirements are focused on "what" needs to be accomplished to achieve desired results and avoids prescriptive requirements of "how" to achieve that result. TO's are in the best position to determine the appropriate management approach suited for their system, rather than a "one size fits all" or "fill in the blank" requirement that could suppress best practices for vegetation management.

Other entities questioned whether the goal of the standard was to "prevent outages" or to "manage vegetation." In Order 693, FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way by maintaining safe clearances between transmission lines and vegetation." The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.

Some entities expressed concern with the mandatory inspection intervals proposed in the standard. The SDT recognizes that a number of Transmission Owners in North America may prefer to set their own inspection intervals. Because there is substantial industry support for an annual inspection interval the SDT believes that the industry is best served with this approach.

Several entities suggested making minor changes to clarify the footnotes. The team did so.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 404-446-2563 or at herb.scrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Paul B. Johnson	American Electric Power	1	Affirmative	American Electric Power believes that the phrase "arboricultural activities or horticultural or agricultural activities" was mistakenly introduced into Footnotes 2 and 4, and should be deleted from both footnotes. If the phrase remains in the Standard, it may empower orchard growers, landowners and others to plant trees on the right of way and challenge Transmission Owners' rights to perform maintenance on the presumption that the standard will exempt the TO from violating the outage or encroachment requirements. For increased clarity, AEP offers the following change to the second paragraph of M1, as well as the second paragraph of M2. The original text "If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation" should be replaced

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
				with “If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation growing into or blowing together with the conductor within the ROW, this shall be considered the equivalent of a Real-time observation. A brief encroachment caused by falling vegetation passing through the MVCD is not considered an encroachment in this requirement”.
Response: Thank you for your comments. The SDT made suggested changes to the footnotes as proposed. Regarding the issue of fall-ins, the SDT is sympathetic to your concern. In fact, the SDT had originally crafted language similar to that which you suggested. However, due to concerns expressed by regulators and others, the exemption for encroachment violations due to falling vegetation from inside the right of way was removed.				
Robert D Smith	Arizona Public Service Co.	1	Negative	Overall comment: The objective, as written, is about outages that can lead to cascading and not about reliability. Recommended change to Standard Objective: To maintain a reliable electric transmission system, implement a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW.
Response: The SDT thanks you for your comment. With respect to the Purpose as written in the proposed standard, the language clearly states “To improve the reliability of the electric Transmission system…” The SDT made it a point to keep the Purpose as concise as possible without getting into issues that are covered further in the body of the standard.				
John Bussman	Associated Electric Cooperative, Inc.	1	Negative	R1 - “Each Transmission Owner shall manage vegetation to prevent encroachments of the types shown below, into the Minimum Vegetation Clearance Distance (MVCD) of any of its applicable line(s) identified as an element of an Interconnection Reliability Operating Limit (IROL) in the planning horizon by the Planning Coordinator; or Major Western Electricity Coordinating Council (WECC) transfer

Voter	Entity	Segment	Vote	Comment
				path(s); operating within its Rating and all Rated Electrical Operating Conditions...” The following is my preliminary comment on this requirement. R1 - Associated Electric Cooperative Inc wants to thank the SDT for their hard work and all the effort associated with this standard. However we currently disagrees with the inclusion in this requirement of any and all IROLs identified within the entire planning horizon (typically 10 years or more). Associated Electric certainly agrees that in real time and in the near term sub 200 kV elements of an IROL should be subject to R1. It seems unreasonable, however, to include a sub 200 kV transmission line that might become an IROL element 10 years in the future. Perhaps the time frame could be limited to the Transmission Owner’s planned maintenance cycle.
Response: The SDT thanks you for your comment, and has revised the Standard’s effective dates (exceptions) accordingly.				
Gregory S Miller	Baltimore Gas & Electric Company	1	Affirmative	There seems to be a marginal level of improvement over the previous drafts.
Response: The SDT thanks you for your comment.				
Joseph S. Stonecipher	Beaches Energy Services	1	Negative	R1 and R2 Requirement reads: "Each Transmission Owner shall manage to prevent encroachment ....". The results of manage would be invoices of tree trimming actually performed, documentation of a vegetation management program that would be managed to, etc. However, the Measures proposed are all actual outages which are neither

Voter	Entity	Segment	Vote	Comment
				evidence of management nor evidence of encroachment since there can be encroachment without an outage, and in fact, many if not most encroachments do not result in outages. Hence, the Measures are inconsistent with the Requirements. Further, there is ambiguity of the action required in requirements R1 and R2 - e.g., do entities need evidence that they: 1) "manage", or 2) "prevent encroachment"; or 3) as implied by the Measures, prevent vegetation related outages? In other words, what needs to be proven through evidence? Certainly the third, prevent vegetation related outages, is not in the Requirement; yet, that us what is proposed for the Measures, highlighting the inconsistency between Requirements and Measures. But, how would the ambiguity between "manage" and "prevent encroachment" be resolved? One auditor could interpret that the Requirement is to "manage" and accept a vegetation management program and plan and proof that the plan was executed as appropriate evidence. Another auditor could interpret that "prevent" is the key word and look for evidence proving that there was never a vegetation encroachment. How would evidence be produced to provide the auditor that vegetation never encroached? Would video cameras and other surveillance measures need to operate 24 hours a day? Would we cause an entity to survey the lines periodically? One can easily see that "prevent encroachment" is inappropriate here since it is infeasible to create evidence of compliance.

Response: The SDT thanks you for your comments. In Order 693, FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances**

Voter	Entity	Segment	Vote	Comment
between transmission lines and vegetation" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.				
Donald S. Watkins	Bonneville Power Administration	1	Affirmative	R2. Do you agree? If answer is no, please explain. BPA prefers the stratified levels of violation severity presented in the table for R1 and R2. Foot note # 2 on page 8 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. Foot note # 4 on page 12 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. In response to comments received that requirement R3 is unclear with respect to intent, the SDT added "maintenance strategies." Do you agree this clarifies the intent? If answer is no, please offer alternative language. The TO procedures / policies and specifications shall demonstrate the TO's ability to manage the system at all rated conditions to maintain reliability. BPA believes that the intent is clear, but the fundamental approach of using the MVCD (table 2) to manage a vegetation program is still problematic. These values are flashover distances and are way too close. This is acknowledged in a footnote to table 2 but no identification of allowable buffers/distances between energized phase conductors at rated temperatures and vegetation is discussed (this is left up the transmission owners). Clarity is needed on this topic. Setting a finite distance limit based on recognized standards, good science and risk avoidance should be done for the industry. BPA has previously made this comment during the drafting of the

Voter	Entity	Segment	Vote	Comment
				standard. It was not addressed then, nor has it been addressed now.
Response: The SDT thanks you for your comments. The footnotes were changed to conform with your suggestions. With respect to comments about the MVCD, R3 does not suggest the MVCD be used as a distance to manage vegetation. The MVCD was established as a beginning of a series of "building blocks" for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions. R3 requires that a Transmission Owner consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this "building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD In a performance based standard, requirements are focused on "what" needs to be accomplished to achieve desired results and avoids prescriptive requirements of "how" to achieve that result. TO's are in the best position to determine the appropriate management approach suited for their system, rather than a "one size fits all" that could suppress best practices for vegetation management.				
Randall McCamish	City of Vero Beach	1	Negative	Vero Beach's concern is that entities may not be able prove compliance with the standard. R1 and R2 say that: "Each Transmission Owner shall manage vegetation to prevent encroachments ...". If the requirements were interpreted such that "manage" is the operative word, then, we are OK because we can provide evidence of managing a program, such as a vegetation management plan and evidence of executing that plan (which does not align with the Measures). However, that 1) would cause the standard to not be performance based, and 2) it would be duplicative of the other requirements of the standard. If the requirements were interpreted with "prevent encroachment" as the operative phrase (which would be an

Voter	Entity	Segment	Vote	Comment
				incorrect interpretation from the construct of the sentence) there is no way to provide sufficient evidence that encroachment was prevented during the audit-period. The suggested Measures are not sufficient evidence to prove compliance with that interpretation of the requirement. For instance, most encroachments do not result in outages; hence, lack of outages cannot prove that there were no encroachments, and real time observations are insufficient because it is a spot-check that does not cover the audit period. There are other weaknesses in the standard, such as R4 being un-measurable therefore unenforceable. However, in the guilty until proven innocent paradigm we live in, FMPA's primary concern is that industry could be put into a no-win situation of not being able to prove compliance with the standard if R1 and R2 are interpreted as "prevent encroachment", and if R1 and R2 are interpreted as "manage" then it is not a performance based standard as advertised. Vero Beach suggests one of two approaches: 1. Performance based focused on preventing vegetation related outages. For instance: "Each Transmission Owner shall prevent vegetation related outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. 2. Modify the standard to be similar to the currently mandatory non-results based standard and focus on the word "manage". This would essentially mean eliminating R1

Voter	Entity	Segment	Vote	Comment
				and R2 since the rest of the standard focuses on having a plan and managing to that plan.
Response: The SDT thanks you for your comments. In Order 693, FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.				
Danny McDaniel	Cleco Power LLC	1	Negative	Cleco disagrees with the SDT revising the definition for Right-of-Way (ROW). Right-of-Way is a term that has had a consistent meaning throughout history. If NERC tries to redefine the term, it will only add confusion because most entities will not reference the NERC glossary for a term which is widely used in the industry. In lieu of "Active Transmission Line ROW", please use another term such as Transmission Corridor. No assumptions would be made when reading in the Standard the the Entity is to maintain vegetation located within the Transmission Corridor. Since the term is not commonly used, the NERC glossary would be referenced. Also, Cleco disagrees that an encroachment into the MCVD that does not cause an outage should be considered non-compliant as stated in R1 and R2. The encroachment should only be reportable similar to misoperations as is in the PRC-004 standard.
Response: Thank you for your comments. The existing ROW definition in the glossary was created by and for the FAC-003-1 and was moved there when that standard was adopted. The definition includes a series of options that give the Transmission Owner latitude in establishing ROW width. It does not require selecting a single method for its system. The term "blowout standard" is not capitalized and is not a defined				

Voter	Entity	Segment	Vote	Comment
term. This phrase in the definition allows a Transmission Owner to use its internal engineering standards or the general engineering standards that were in effect when the line was constructed to determine the ROW width. The SDT has limited the definition of Right-of-Way to a corridor of land with a defined width to operate a transmission line. This does not include danger tree rights. The definition of the MVCD is now added to this Standard. While use of the pre-2007 records is a compliance issue and is not in the purview of the SDT, it is the intent of the language in the definition that you could use this information. Regarding your second comment, R3 does not suggest the MVCD be used as a distance to manage vegetation. The MVCD was established as a beginning of a series of "building blocks" for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions. R3 requires that a Transmission Owner consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this "building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD Other related requirements of this "Defense in Depth" Standard serve to address any number of scenarios which may arise or hinder the TO's ability to always strictly adhere to the management approach(s) established within R3. Thus the other requirements of this Standard provide the latitude for appropriate actions to remedy the condition without penalty. Further, trees which have encroached inside the MVCD are evidence of a deficiency in vegetation maintenance.				
Christopher L de Graffenried	Consolidated Edison Co. of New York	1	Affirmative	Reply to Question 5 on Comment Form: The added language for the annual work plan percentage complete calculation is shown in R7 not M7 as stated in the question. In the Guideline and Technical Basis Section for Requirement R6, there is a sample calculation shown for the amount of lines the TO failed to inspect. An example should also be included for Requirement R7 since there is some confusion regarding how modifications to the work plan affect the calculation. In the Lower VSL column for R7, it states that the TO failed to complete up to 5% of its annual vegetation work plan (including modifications if any). If a TO operates 100 lines and submits a justified modification that affects 10 miles of

Voter	Entity	Segment	Vote	Comment
				lines, the total number of units in the final amended plan is 90 miles. When you read the VSL, it is somewhat confusing since the information in parenthesis says that the calculation 'includes' the modifications. Should it state 'excludes modifications if any' or the VSLs can simply be re-written to state that ..The TO failed to complete up to x% of the final amended plan.' Also, the VSLs in R6 and R7 should be consistent with each other: R6 says '...TO failed to inspect 5% or less.....' and R7 says '...TO failed to complete up to 5%....' They both should use the same verbiage in each VSL whether it is 'x% or less' or 'up to and including x%.'
Response: The SDT thanks you for your comments. The percentage should be based on the plan as modified. The SDT has changed the language in the standard to reflect this more clearly, and has modified the VSLs to be consistent as you have suggested.				
Robert Martinko	FirstEnergy Energy Delivery	1	Affirmative	FirstEnergy supports standard FAC-003-2 and would appreciate consideration of our comments submitted through the formal comment period.
Response: The SDT thanks you for your comments. Please see our consideration of your comments within the responses to the formal comments.				
Luther E. Fair	Gainesville Regional Utilities	1	Negative	1. It would seem that the impetus for FAC003 is to eliminate vegetation related outages within the rights-of-way as defined and subject to the exclusions as stated in footnote 2. Thus the requirement is to manage the ROW to prevent vegetation related sustained outages with the measure being no outages. With grow-ins and fall-ins from within the defined ROW being controllable factors.

Voter	Entity	Segment	Vote	Comment
				2. Including encroachments leaves the door open for fines to be imposed with no actual outage(s) having occurred. This may be like being found guilty of a crime that has not yet taken place. 3. Combine vegetation related sustained outages by “grow-ins” and “blowing together of lines and vegetation located inside the ROW” as one item as they are both consequences of the growth of vegetation either vertically and horizontally. 4. Leave vegetation related sustained outages by “fall-in” as a standalone as this will be related to structural problems occurring from a variety of sources. 5. Combine R3 and R7 to R1 (development and implementation of a Transmission Vegetation Management Plan which shall include documented maintenance strategies or procedures or processes or specifications, delineation of an annual work plan and completion of same). Thus this would be the competency based requirements as a program without execution is meaningless. 6. R1 and R2 become R2 and R3.
Response: The SDT thanks you for your comments. In Order 693, FERC was very specific that “…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**” (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct				

Voter	Entity	Segment	Vote	Comment
inspections in which clearances are evaluated.				
Ted E Hobson	JEA	1	Negative	Need to align the "measures" with the standard requirement language and the performance-based philosophy.
Response: The SDT thanks you for your comments. We are not quite clear as to what misalignment you refer to between the standard language and the measures. The SDT went to great lengths to ensure continuity between the requirements and the measures. While this standard was a first attempt at a "Results Based" approach, the SDT did have limitation in deciding what could be excluded from the standard. This standard has a mixture of the three types of requirements that comprise a results based approach: 1) Performance Based 2) Risk Based and 3) Competency Based. Having only performance-based requirements would not have resulted in a comprehensive, proactive standard.				
Michael Gammon	Kansas City Power & Light Co.	1	Negative	The Standard lacks clarity regarding the facilities that are subject to Requirement 7. It is important that a Standard be clear and not introduce ambiguity or confusion. There are several references throughout the Standard to "for all applicable lines" and it should be made clear the work plan is specific to "all applicable lines".
Response: The SDT thanks you for your comments. The team has made the appropriate modifications where necessary.				
Stan T. Rzad	Keys Energy Services	1	Negative	Concern is that entities may not be able prove compliance with the standard. R1 and R2 say that: "Each Transmission Owner shall manage vegetation to prevent encroachments ...". If the requirements were interpreted such that "manage" is the operative word, then, we are OK because we can provide evidence of managing a program, such as a vegetation management plan and evidence of executing that plan (which does not align with the Measures). However, that 1) would cause the standard to not be performance based, and 2) it would be duplicative of the

Voter	Entity	Segment	Vote	Comment
				other requirements of the standard. If the requirements were interpreted with "prevent encroachment" as the operative phrase (which would be an incorrect interpretation from the construct of the sentence) there is no way to provide sufficient evidence that encroachment was prevented during the audit-period. The suggested Measures are not sufficient evidence to prove compliance with that interpretation of the requirement. For instance, most encroachments do not result in outages; hence, lack of outages cannot prove that there were no encroachments, and real time observations are insufficient because it is a spot-check that does not cover the audit period. There are other weaknesses in the standard, such as R4 being un-measurable therefore unenforceable. However, in the guilty until proven innocent paradigm we live in, FMPA's primary concern is that industry could be put into a no-win situation of not being able to prove compliance with the standard if R1 and R2 are interpreted as "prevent encroachment", and if R1 and R2 are interpreted as "manage" then it is not a performance based standard as advertised. One of two approaches are suggested: Performance based focused on preventing vegetation related outages. For instance: "Each Transmission Owner shall prevent vegetation related outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. Modify the standard to be similar to the currently mandatory

Voter	Entity	Segment	Vote	Comment
				non-results based standard and focus on the word "manage". This would essentially mean eliminating R1 and R2 since the rest of the standard focuses on having a plan and managing to that plan.
Response: The SDT thanks you for your comments. In Order 693, FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.				
Walt Gill	Lake Worth Utilities	1	Negative	CLWU's concern is that entities may not be able prove compliance with the standard. R1 and R2 say that: "Each Transmission Owner shall manage vegetation to prevent encroachments ...". If the requirements were interpreted such that "manage" is the operative word, then, we are OK because we can provide evidence of managing a program, such as a vegetation management plan and evidence of executing that plan (which does not align with the Measures). However, that 1) would cause the standard to not be performance based, and 2) it would be duplicative of the other requirements of the standard. If the requirements were interpreted with "prevent encroachment" as the operative phrase (which would be an incorrect interpretation from the construct of the sentence) there is no way to provide sufficient evidence that encroachment was prevented during the audit-period. The suggested Measures are not sufficient evidence to prove compliance with that interpretation of the requirement. For instance, most encroachments do not result in outages; hence, lack of outages cannot prove that there were no

Voter	Entity	Segment	Vote	Comment
				encroachments, and real time observations are insufficient because it is a spot-check that does not cover the audit period. There are other weaknesses in the standard, such as R4 being un-measurable therefore unenforceable. However, in the guilty until proven innocent paradigm we live in, FMPA's primary concern is that industry could be put into a no-win situation of not being able to prove compliance with the standard if R1 and R2 are interpreted as "prevent encroachment", and if R1 and R2 are interpreted as "manage" then it is not a performance based standard as advertised. CLWU suggests one of two approaches: 1. Performance based focused on preventing vegetation related outages. For instance: "Each Transmission Owner shall prevent vegetation related outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. 2. Modify the standard to be similar to the currently mandatory non-results based standard and focus on the word "manage". This would essentially mean eliminating R1 and R2 since the rest of the standard focuses on having a plan and managing to that plan..
Response: The SDT thanks you for your comments. In Order 693, FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.				

Voter	Entity	Segment	Vote	Comment
Saurabh Saksena	National Grid	1	Affirmative	The revised ROW definition emphasizes the ROW width needed to operate the transmission line(s). It is National Grid's interpretation that the width established when the line was constructed is the width to be maintained. This width is documented in engineering drawings, per-2007 vegetation records or blow-out standards. This definition does not imply that danger tree rights beyond the constructed and maintained width are incorporated in the definition; therefore fallins - from outside the ROW but within an area with danger tree rights would not be considered fallin-ins from within the ROW. National Grid would like the SDT to comment on this interpretation in its response to these comments.
Response: Your interpretation is consistent with the intent of the definition that the SDT provided. However the definition includes a series of options that give the Transmission Owner latitude in establishing ROW width. It does not require selecting a single method for its system. This phrase in the definition allows a TO to use its internal engineering standards or the general engineering standards that were in effect when the line was constructed to determine the ROW width. The SDT has limited the definition of Right-of-Way to a corridor of land with a defined width to operate a transmission line. This does not include danger tree rights.				
Michael T. Quinn	Oncor Electric Delivery	1	Affirmative	In footnote 2 (pg. 8) and 4 (page 10), the wording "arboricultural activities or horticultural or agricultural activities" should be deleted and replaced with "or removal of, installation of, or digging around vegetation."
Response: The SDT thanks you for your comments. The footnotes have been changed.				
John C. Collins	Platte River Power Authority	1	Negative	Vegetation Inspection: Is the intent of "... and those vegetation conditions under the TO's control" to clarify that an entity must have ownership of the transmission line and right-of-way in addition to maintenance or operational responsibility (control), or something different? In situations

Voter	Entity	Segment	Vote	Comment
				where a TO owns one circuit on a double circuit, but the other circuit, facilities and ROW belong to another TO who has maintenance, and vegetation management responsibility, who would be responsible for violations? If the definition was modified to allow both maintenance and vegetation inspections to be performed concurrently, the intent might be clearer if it read: “This may be combined with other line inspections”, or “This may be combined with a maintenance inspection” opposed to a general line inspection. R1 and R2: Does R1 correlate to facilities in 4.2.2. and 4.2.3. (overhead transmission lines operated below 200 kV) and R2 correlate to facilities in 4.2.1. (overhead transmission lines operated at 200kV or higher)? It isn’t clear why the two requirements are split. Could it be one requirement which reads “...identified as a facility in Section 4.2”? R4: Our current imminent threat procedure requires a call to the Manager who confirms the existence of a vegetation condition that is likely to cause a Fault at any moment prior to notifying the control center. We assume notification, without any intentional time delay, would take place after managerial confirmation but feel like the enforcement authorities could interpret this differently based on how it is written in R4. If the intent of the requirement is how we interpret it, the requirement might be clearer if it read: After a Transmission Owner has confirmed a vegetation condition likely to cause a Fault at any moment, they shall notify the control center holding switching authority for the associated applicable transmission line, without any

Voter	Entity	Segment	Vote	Comment
				intentional delay.
Response: The SDT thanks you for your comment. With regard to responsibility for a violation, the TO is the accountable party even if it has an agreement with another TO to inspect and manage vegetation. With regard to your suggestion in changing the definition of Vegetation Inspection, the SDT does not believe the proposed changes are necessary for the definition to be clear. With regard to R1 and R2, they applicability applies to 4.2.1 thru 4.2.3. The distinction between the requirement is R1 applies to all lines designated as having an Interconnection Reliability Operating Limit (IROL) in the planning horizon by the Planning Coordinator; or lines designated as Major Western Electricity Coordinating Council (WECC) transfer path(s). With regard to your imminent threat procedure, the standard is not prescriptive to define a TO's imminent threat procedure. So, if your procedure includes managerial confirmation, then this would not be considered intentional delay.				
Sammy Roberts	Progress Energy Carolinas	1	Affirmative	There needs to be a change in the footnote 2 and footnote 4 to remove the exemption for "arboricultural activities or horticultural or agricultural activities" and replace it with the term "or installation of."
Response: The SDT thanks you for your comments. The footnotes have been changed.				
Laurie Williams	Public Service Company of New Mexico	1	Negative	PNM is voting negative but offers the following comments to improve the standard. 1. The last sentence of the Background on page 7 states: Thus, this Standard's emphasis is on vegetation grow-ins. However, R1 says that we shall manage encroachments as follows: R1. Each Transmission Owner shall manage vegetation to prevent encroachment that could result in a Sustained Outage encroachments of the types shown

Voter	Entity	Segment	Vote	Comment
				below, into the Minimum Vegetation Clearance Distance (MVCD) of....... 2. An encroachment due to a fall-in from inside the active transmission line Right-of-Way (ROW) that caused a vegetation-related Sustained Outage, This seems contradictory. 2. Fac-003-2 makes reference to FAC-014 and a “Planning Coordinator” in section 4.2.2 of Applicability: pg 5 see below: 4.2.2. Overhead transmission lines operated below 200kV having been identified as included in the definition of an Interconnection Reliability Operating Limit (IROL) under NERC Standard FAC-014 by the Planning Coordinator. In addition, on pg 8, R1 of FAC-003-2 makes reference to the “planning coordinator” However, FAC-014 makes no reference, or at least it is inconsistent, to a “Planning Coordinator” See below: Taken from FAC-014 4. Applicability 4.1. Reliability Coordinator 4.2. Planning Authority 4.3. Transmission Planner 4.4. Transmission Operator The terminology and definitions seem to be inconsistent.

Voter	Entity	Segment	Vote	Comment
				3. R1 and R2 are the same requirements with different applicabilities. R1 applies to lines that are connected to WECC, IROL, etc. R2 applies to all other applicable lines that are NOT an element of WECC or IROL. My Question is: If the line is not part of WECC or IROL or any other connection then, how is it applicable to the Standard? 4. R7 says the TO shall complete a %100 of annual plan but allows for modifications that include: Change in expected growth rate/ environmental factors Major storms Circumstances that are beyond the control of a Transmission Owner5 Rescheduling work between growing seasons Crew or contractor availability/ Mutual assistance agreements Identified unanticipated high priority work Weather conditions/Accessibility Permitting delays Land ownership changes/Change in land use by the landowner Funding adjustments (increase or decrease) Emerging technologies [VRF - Medium] [Time Horizon - Operations Planning] The requirement says we shall complete a %100 of the annual plan however, some of the modifications have historically taken over a year to mitigate. SHALL should be

Voter	Entity	Segment	Vote	Comment
				replaced with SHOULD with acceptable modifications and without compromising integrity of system.
Response: The SDT thanks you for your comments. Item 1: It is intended that the Standard will cover any situation within the ROW that causes an encroachment into the MVCD including fall-ins, grow-ins or blowing-together. The arrangement of the Violation Severity Levels for R1. and R2. emphasize that a grow-in results in the greatest risk to a power system, and also is the most egregious and severe failure to meet the intent of these requirements. Item 2: The term Planning Authority (PA) included in FAC-014 was replaced by NERC in the functional model Version 5 with Planning Coordinator. Where references to PA are included in legacy Standards, Planning Coordinator is now used as follows Planning Coordinator (Planning Authority). Obviously, proposed new Standards or versions must use the currently accepted terms. Item 3: R1 and R2 are dealing with the differentiation between lines that fall into IROL/WECC Transfer Path definition and those lines that do not. Keep in mind that this standard refers to all transmission lines over 200-kV. Item 4: The SDT believes replacing the word "shall" with the word "should" in Requirement 7 changes the requirement to a recommendation.				
Pawel Krupa	Seattle City Light	1	Affirmative	The revisions to the proposed FAC-003-2 Standards produced a better version through greater clarity, appropriate pragmatism, and technical foundation; A few good points that highlight this follow: 1. Definition of Terms Used in Standard: The revised definition of Right-of-Way (ROW) establishes the width of the corridor from a technical basis with the following statement "The width of the corridor is established by engineering or construction standards..." 2. Introduction, Applicability, Section 4.2 Facilities: Section 4.2.4 which pertains to substations clarifies that this standard does not apply to applicable transmission lines, inside the substation, just to "any portion of the span of the

Voter	Entity	Segment	Vote	Comment
				transmission line that is crossing the substation fence". 3. Requirements and Measures: Requirement 1 underscores sensible purpose by replacing the wording of "preventing outages from vegetation" to "manage vegetation to prevent encroachments..." 4. Guideline and Technical Basis Section: Requirement 7 contains a great practicle reference explanation as it pertains to the annual work plan. Requirement 7 explains: ..." the vegetation management approach should use the full extent of the Transmission Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management in the long term because it reduces the overall potential for encroachment, and it ensures that future planned work and future planned inspection cycles are sufficient".
Response: The SDT thanks you for your comments.				
William G. Hutchison	Southern Illinois Power Coop.	1	Negative	I beleive that the reliability region should have the right to exclude lines below 200KV. Not all lines above 100KV negative impact the BES.
Response: The SDT thanks you for your comment. This issue is presently before FERC and NERC and is outside the scope of the SDT.				
Keith V Carman	Tri-State G & T Association, Inc.	1	Affirmative	There needs to be a change in the footnote 2 and footnote 4 to remove the exemption for "arboricultural activities or horticultural or agricultural activities" and replace it with the term " installation of".

Voter	Entity	Segment	Vote	Comment
Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.				
Brandy A Dunn	Western Area Power Administration	1	Affirmative	There needs to be a change in the footnote 2 and footnote 4 to remove the exemption for "arboricultural activities or horticultural or agricultural activities" and replace it with the term " installation of"
Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.				
Gregory L Pieper	Xcel Energy, Inc.	1	Affirmative	Xcel Energy still believes the requirement in R6 that mandates an annual inspection is an ineffective approach and may actually go against the Commission's determination in FERC Order No. 693. The drafting team's response to our last round of comments on this issue was that "...the SDT was directed by Order 693 to set a minimum inspection criteria". It is clear in Order 693 that the Commission is not satisfied with allowing entities to choose their own inspection cycles, as the standard currently allows. However, we fail to see where the Commission mandated a minimum inspection cycle to be uniformly applied continent-wide. We urge the drafting team to revisit paragraphs 719 through 721 of Order 693. According to paragraph 721, the Commission recognizes that unique intervals by region, "based on local factors", are reasonable and appropriate. By use of the plural term "cycles", FERC anticipates the resolution may include multiple inspection cycles. Furthermore, in paragraph 719, FERC acknowledges that a minimum inspection cycle may not be the only way to address their concern. In fact, mandating an annual inspection cycle may actually go against the Commission's guidance in paragraph 720. Here is an excerpt: "...the

Voter	Entity	Segment	Vote	Comment
				Commission is dissuaded from requiring the ERO to create a backstop inspection cycle at this time. Instead, the Commission agrees that an entity's vegetation management program should be tailored to anticipated growth in the region and take into account other environmental factors. The goal is to assure that transmission owners conduct inspections at reasonable intervals." As an alternative, we propose a mid-cycle inspection. A mid-cycle inspection is based on an interval that is justified with data and technical expertise. A mid-cycle inspection would still require entities to conduct inspections at a specified interval, while allowing for differences based upon "physical and geographic factors". Not only would this approach fully address the Commissions concerns, but it would take into account the interests of stakeholders, landowners and rate-payers. We recognize that a mid-cycle inspection interval is not as easy to audit as an annual requirement, but it is a far more practical and cost-effective approach that, when applied based on an entity's expertise with its own facilities, ensures reliability.
Response: The SDT thanks you for your comments. The SDT recognizes that a number of Transmission Owners in North America may prefer to set their own inspection intervals. The SDT can also see attractiveness for a mid-cycle inspection concept; however, this introduces new complexities in planning, documentation and auditing. Because there is substantial industry support for an annual inspection interval the SDT believes that the industry is best served with this approach.				
Mark B Thompson	Alberta Electric System Operator	2	Abstain	Due to slow vegetation growth rates in many parts of Alberta, not all transmission right-of-ways require annual inspection as required in R6. TOs should be able to include planned inspection cycles in their Transmission Vegetation Management Plan.

Voter	Entity	Segment	Vote	Comment
Response: The SDT thanks you for your comments. In FERC Order 693, para. 721, FERC stated, “The Commission continues to be concerned with leaving complete discretion to the transmission owners in determining inspection cycles, which limits the effectiveness of the Reliability Standard.” The SDT established an inspection cycle at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW. There was a survey of the industry in a previous request for comments to this standard. The response to that survey is the basis for the use of the 1-year period. While there was a range of growth rates across the continent, the SDT had sufficient feedback to recommend the 1-year cycle. The inspection also would cover inspecting for fall-in threats. Please note that vegetation inspections can also be combined with other line inspections.				
Alden Briggs	New Brunswick System Operator	2	Affirmative	The term “encroachment” has to be defined, and the use of that term and the clearances required clarification. The Table listing the clearances also needed clarification.
Response: The SDT thanks you for your comment. The SDT endorses the standard dictionary definition of the term “encroachment” and as such it does not require a NERC-specific definition. The use of encroachment regarding the clearance table is explained in detail in the Technical Reference Document.”				
Richard J. Mandes	Alabama Power Company	3	Affirmative	There needs to be a change in the footnote 2 and footnote 4 to remove the exemption for “arboricultural activities or horticultural or agricultural activities” and replace it with the term “ installation of”.
Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.				
Steven Norris	APS	3	Negative	The objective, as written, is about outages that can lead to cascading and not about reliability. Recommended change to Standard Objective: To maintain a reliable electric transmission system, implement a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW.

Voter	Entity	Segment	Vote	Comment
Response: The SDT thanks you for your comment. With respect to the Purpose as written in the proposed standard, the language clearly states “To improve the reliability of the electric Transmission system…”. The SDT made it a point to keep the Purpose as concise as possible without getting into issues that are covered further in the body of the standard.				
Rebecca Berdahl	Bonneville Power Administration	3	Affirmative	In R1 and R2 and their associated VSLs, the SDT added the phrase “in order of increasing severity” and added the sentence, “The types of encroachments are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO’s vegetation maintenance program.” to the Rationale boxes for R1/R2. Do you agree? If answer is no, please explain. BPA prefers the stratified levels of violation severity presented in the table for R1 and R2. Foot note # 2 on page 8 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. Foot note # 4 on page 12 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. In response to comments received that requirement R3 is unclear with respect to intent, the SDT added “maintenance strategies.” Do you agree this clarifies the intent? If answer is no, please offer alternative language. The TO procedures / policies and specifications shall demonstrate the TO’s ability to manage the system at all rated conditions to maintain reliability. BPA believes that the intent is clear, but the fundamental approach of using the MVCD (table 2) to manage a vegetation program is still

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				problematic. These values are flashover distances and are way too close. This is acknowledged in a footnote to table 2 but no identification of allowable buffers/distances between energized phase conductors at rated temperatures and vegetation is discussed (this is left up the transmission owners). Clarity is needed on this topic. Setting a finite distance limit based on recognized standards, good science and risk avoidance should be done for the industry. BPA has previously made this comment during the drafting of the standard. It was not addressed then, nor has it been addressed now.
Response: The SDT thanks you for your comments. Footnotes #2 and #4 have been changed to reflect your suggestion to clarify arboricultural or horticultural or agricultural activities. With respect to comments about the MVCD, R3 does not suggest the MVCD be used as a distance to manage vegetation. The MVCD was established as a beginning of a series of "building blocks" for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions. R3 requires that a Transmission Owner consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this "building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD In a performance based standard, requirements are focused on "what" needs to be accomplished to achieve desired results and avoids prescriptive requirements of "how" to achieve that result. TO's are in the best position to determine the appropriate management approach suited for their system, rather than a "one size fits all" or "fill in the blank" requirement that could suppress best practices for vegetation management.				
Matt Culverhouse	City of Bartow, Florida	3	Negative	The suggested Measures are not sufficient evidence to prove compliance with that interpretation of the requirement. For instance, most encroachments do not result in outages; hence, lack of outages cannot prove that there were no encroachments, and real time observations

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				are insufficient because it is a spot-check that does not cover the audit period. There are other weaknesses in the standard, such as R4 being un-measurable therefore unenforceable. However, in the guilty until proven innocent paradigm we live in, FMPA's primary concern is that industry could be put into a no-win situation of not being able to prove compliance with the standard if R1 and R2 are interpreted as "prevent encroachment", and if R1 and R2 are interpreted as "manage" then it is not a performance based standard as advertised.
Response: The SDT thanks you for your comments. In Order 693, FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated. Also please reference footnote 3.				
Bryan Y Harper	Cleco Utility Group	3	Negative	Cleco disagrees with the SDT revising the definition for Right-of-Way (ROW). Right-of-Way is a term that has had a consistent meaning throughout history. If NERC tries to redefine the term, it will only add confusion because most entities will not reference the NERC glossary for a term which is widely used in the industry. In lieu of "Active Transmission Line ROW", please use another term such as Transmission Corridor. No assumptions would be made when reading in the Standard the the Entity is to maintain vegetation located within the Transmission Corridor. Since the term is not commonly used, the NERC glossary would be referenced. Also, Cleco disagrees that an encroachment into the MCVD

Voter	Entity	Segment	Vote	Comment
				that does not cause an outage should be considered non-compliant as stated in R1 and R2. The encroachment should only be reportable similar to misoperations as is in the PRC-004 standard.
Response: Thanks for your comments. The existing ROW definition in the glossary was created by and for the FAC-003-1 and was moved there when that standard was adopted. The definition includes a series of options that give the Transmission Owner latitude in establishing ROW width. It does not require selecting a single method for its system. The term blowout standard is not capitalized and is not a defined term. This phrase in the definition allows a Transmission Owner to use its internal engineering standards or the general engineering standards that were in effect when the line was constructed to determine the ROW width. The SDT has limited the definition of Right-of-Way to a corridor of land with a defined width to operate a transmission line. This does not include danger tree rights. The definition of the MVCD is now added to this Standard. While use of the pre-2007 records is a compliance issue and is not in the purview of the SDT, it is the intent of the language in the definition that you could use this information. Regarding your second comment, the MVCD was established as a beginning of a series of "building blocks" for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions. R3 requires that a Transmission Owner consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this "building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD. Other related requirements of this "Defense in Depth" Standard serve to address any number of scenarios which may arise or hinder the TO's ability to always strictly adhere to the management approach(s) established within R3. Thus the other requirements of this Standard provide the latitude for appropriate actions to remedy the condition without penalty. Further, trees which have encroached inside the MVCD are evidence of a deficiency in vegetation maintenance.				
Peter T Yost	Consolidated Edison Co. of New York	3	Affirmative	Reply to Question 5 on Comment Form: The added language for the annual work plan percentage complete calculation is shown in R7 not M7 as stated in the question. In the Guideline and Technical Basis Section for Requirement R6, there is a sample calculation shown for the amount of lines the TO failed to inspect. An example should

Voter	Entity	Segment	Vote	Comment
				also be included for Requirement R7 since there is some confusion regarding how modifications to the work plan affect the calculation. In the Lower VSL column for R7, it states that the TO failed to complete up to 5% of its annual vegetation work plan (including modifications if any). If a TO operates 100 lines and submits a justified modification that affects 10 miles of lines, the total number of units in the final amended plan is 90 miles. When you read the VSL, it is somewhat confusing since the information in parenthesis says that the calculation 'includes' the modifications. Should it state 'excludes modifications if any' or the VSLs can simply be re-written to state that ..The TO failed to complete up to x% of the final amended plan.' Also, the VSLs in R6 and R7 should be consistent with each other: R6 says '...TO failed to inspect 5% or less.....' and R7 says '...TO failed to complete up to 5%....' They both should use the same verbiage in each VSL whether it is 'x% or less' or 'up to and including x%.'
Response: The SDT thanks you for your comments. Your correction is accurate. The percentage should be based on the plan as modified. The SDT has changed the language in the standard to reflect this more clearly. The VSLs have been modified to be consistent as suggested.				
David A. Lapinski	Consumers Energy	3	Negative	Comments on FAC-003-2 February 25, 2011 Consumers Energy submits the following comments on FAC-003-2: In general we are please with FAC-003-2 and the many clarifications that the STD has made in this version of the standard. However, we do have one major disagreement with the STD and cannot support this standard as drafted.

Voter	Entity	Segment	Vote	Comment
				We disagree with the use of the Minimum Vegetation Clearance Distance (MVCD) developed by the drafting team for Requirements R1 and R2. These distances are not the design distances used for designing and constructing transmission facilities as stated in the document for minimum distances between conductors and grounded objects. The proposed Table 2 provides a distance of 3.12 feet as the acceptable distance for an alternate current 345kV line at sea level. This distance is considerably less than the distance used for line design to separate the grounded tower structure from the energized conductor. If the distance in Table 2 is acceptable to prevent energized portions of a transmission line from grounding to a tree why then is this distance not the design criteria used for tower design to prevent flashover from conductor to tower? The STD needs to explain why a ground tree should have a different standard that a grounded steel tower or wood pole structure. The STD erroneously viewed the possibility of transient over voltage as only occurring during re-energizing and not from natural events such as a lightning strike that can occur and does occur to energized operating lines. Secondly, the proposed distances in Table 2 are considerably less than the distances specified in OSHA requirements for air gap clearance required by tree workers to safely remove trees or limbs from conductors energized at the voltages specified. A transmission owner/operator could let a tree grow to within 3.5 feet of a 345 kV line and not be in violation of this proposed standard. To remove the tree, the

Voter	Entity	Segment	Vote	Comment
				line would have to be de-energized, tagged, tested de-energized, and grounded. Working clearance would have to be established by the operating entity and then the tree crew could remove the tree. The net result is the loss of the capacity of the line because an outage was forced on the line in order to remove the tree that did not trigger a violation of FAC-003-2. This situation, in our opinion, is a violation of the intent of the standard, which is to ensure the continued operation of the line. Therefore, the minimum distance any tree should be able to approach a conductor is more than the minimum requirement for air gap distance between the tree and conductor as required by OSHA worker standards. The STD did not like referring to another standard to provide the distance requirements for R1 and R2. This can be alleviated by putting in a table with the IEEE 516 distances but not reference it as the IEEE 516 standard. The distances provided in the current draft do not adequately provide or ensure the continued safe operation of the transmission facilities in the United States and the reasoning for the distances provided is unfounded and not based on current design practices.

Response: The SDT thanks you for your comments. You are correct that these distances do not represent complete design specifications for towers, nor define and describe safe worker approach distances. These practices are correctly specified in the other standards you referenced. The SDT feels the standard is clear in that regard. The footnote associated with the Table 2 distances clearly states that these are only distances to prevent flashover under appropriate conditions. The SDT would also like to point out that the transient overvoltage factors used to derive these distances are the maximums normally seen with a transmission line in steady state service. Thus, a tower design would have to account for the larger overvoltage factors that are possible while taking lines out of service.

As has been stated before, these distances were derived using a known set of line design equations and only represent distances that will prevent spark-over from the transmission line to a grounded object. These are not distances to be managed to – they have been established as a beginning of a series of “building blocks” for a program to ensure reliability of a

Voter	Entity	Segment	Vote	Comment
Transmission line within its rating and all rated electrical operating conditions. R3 requires that a Transmission Owner' consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this "building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD. These distances are smaller than safety standard distances that have many other factors involved in the determination, such as inadvertent human movement and larger safety factors. In regard to the over-voltages caused by lightning, even the maximum overvoltage factors contained in the IEEE-516 tables do not account for these.				
Russell A Noble	Cowlitz County PUD	3	Negative	Referring back to Cowlitz' negative vote made on the 7/9-19/2010 ballot, Cowlitz tried to convey the problem that the statement in R4 "without intentional time delay" will require subjective judgment on the part of the auditor. In other words, maintaining equal auditing standard throughout the interconnection will be impossible with this verbiage in a requirement. Cowlitz agrees with the SDT that establishing an equitable time frame is very difficult (it may be impossible!); however leaving it to the judgment of the auditor to determine whether an intentional delay was made is most disagreeable. Cowlitz respectfully points out that the SDT did not adequately address the subjective nature the auditor is forced into with this requirement. If establishing "[t]he time required by the to report an issue is subject to many variables..." and "[f]or this reason it is difficult to establish a time period which would fairly apply to all TO's," how does leaving this to the auditor to decide going to make it any better?
Response: The SDT believes that it was not prudent to suggest a quantitative time element for notification in R4. The technical reference offers examples of acceptable unintentional delays for your review. The SDT notes that this language is already embodied in at least one other FERC-approved, in-force Standard.				

Voter	Entity	Segment	Vote	Comment
Kevin Querry	FirstEnergy Solutions	3	Affirmative	FirstEnergy supports standard FAC-003-2 and would appreciate consideration of our comments submitted through the formal comment period.
Response: The SDT thanks you for your comments. Please see our consideration of your comments within the responses to the formal comments.				
Lee Schuster	Florida Power Corporation	3	Affirmative	There needs to be a change in the footnote 2 and footnote 4 to remove the exemption for “arboricultural activities or horticultural or agricultural activities” and replace it with the term “installation of."
Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.				
Anthony L Wilson	Georgia Power Company	3	Affirmative	There needs to be a change in the footnote 2 and footnote 4 to remove the exemption for “arboricultural activities or horticultural or agricultural activities” and replace it with the term “ installation of”.
Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.				
Charles Locke	Kansas City Power & Light Co.	3	Negative	The Standard lacks clarity regarding the facilities that are subject to Requirement 7. It is important that a Standard be clear and not introduce ambiguity or confusion. There are several references throughout the Standard to "for all applicable lines" and it should be made clear the work plan is specific to "all applicable lines".
Response: The SDT thanks you for your comments. The team has made the appropriate modifications where necessary.				
Mace Hunter	Lakeland Electric	3	Affirmative	R1. Each Transmission Owner shall manage vegetation to prevent encroachments of the types shown below, ------------

Voter	Entity	Segment	Vote	Comment
				---- and all Rated Electrical Operating Conditions.2 1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage, that is not corrected within 5 working days of discovery, Make the same change to R2 Type 1 encroachment and reflect the changes in Table 1. Rational: This condition would enable a entity to discover an encroachment and clear it without having to self report a possible violation as long as the conditions was corrected within 5 working days. The change should encourage extra inspections for problem areas more often than annually as required in R6. There should be no negative consequences for diligent inspection of lines as long as the problem is clear with a defined time such as 5 or 10 working days.
Response: The SDT thanks you for your comment. As a general rule, a revised standard should not be less stringent than the existing standard it replaces. In the existing standard, a violation occurs when the encroachment occurs. A 'find and fix' of five days would be viewed as a lowering of the level of required performance established by the current standard.				
Bruce Merrill	Lincoln Electric System	3	Affirmative	While supportive of the drafting team's efforts, LES believes a change is warranted in Footnote 2 and Footnote 4 to remove the exemption for "arboricultural activities or horticultural or agricultural activities" and replace with the term "installation of". As currently drafted, the wording could potentially be construed to mean that the TO would or could be constrained or refused permission to prune and remove any and all vegetation in the ROW in accordance with the full legal rights of the ROW agreement(s).
Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.				
Don Horsley	Mississippi Power	3	Affirmative	There needs to be a change in the footnote 2 and footnote 4 to remove the exemption for "arboricultural activities or

Voter	Entity	Segment	Vote	Comment
				horticultural or agricultural activities" and replace it with the term " installation of".
Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.				
Terry L Baker	Platte River Power Authority	3	Negative	FAC-003-2 Comments Vegetation Inspection: Is the intent of "... and those vegetation conditions under the TO's control" to clarify that an entity must have ownership of the transmission line and right-of-way in addition to maintenance or operational responsibility (control), or something different? In situations where a TO owns one circuit on a double circuit, but the other circuit, facilities and ROW belong to another TO who has maintenance, and vegetation management responsibility, who would be responsible for violations? If the definition was modified to allow both maintenance and vegetation inspections to be performed concurrently, the intent might be clearer if it read: "This may be combined with other line inspections", or "This may be combined with a maintenance inspection" opposed to a general line inspection. R1 and R2: Does R1 correlate to facilities in 4.2.2. and 4.2.3. (overhead transmission lines operated below 200 kV) and R2 correlate to facilities in 4.2.1. (overhead transmission lines operated at 200kV or higher)? It isn't clear why the two requirements are split. Could it be one requirement which reads "...identified as a facility in Section 4.2"? R4: Our current imminent threat procedure requires a call

Voter	Entity	Segment	Vote	Comment
				to the Manager who confirms the existence of a vegetation condition that is likely to cause a Fault at any moment prior to notifying the control center. We assume notification, without any intentional time delay, would take place after managerial confirmation but feel like the enforcement authorities could interpret this differently based on how it is written in R4. If the intent of the requirement is how we interpret it, the requirement might be clearer if it read: After a Transmission Owner has confirmed a vegetation condition likely to cause a Fault at any moment, they shall notify the control center holding switching authority for the associated applicable transmission line, without any intentional delay.
Response: The SDT thanks you for your comment. With regard to responsibility for a violation, the TO is the accountable party even if it has an agreement with another TO to inspect and manage vegetation. With regard to your suggestion in changing the definition of Vegetation Inspection, the SDT does not believe the proposed changes are necessary for the definition to be clear. With regard to R1 and R2, they applicability applies to 4.2.1 thru 4.2.3. The distinction between the requirement is R1 applies to all lines designated as having an Interconnection Reliability Operating Limit (IROL) in the planning horizon by the Planning Coordinator; or lines designated as Major Western Electricity Coordinating Council (WECC) transfer path(s). With regard to your imminent threat procedure, the standard is not prescriptive to define a TO's imminent threat procedure. So, if your procedure includes managerial confirmation, then this would not be considered intentional delay.				
Dana Wheelock	Seattle City Light	3	Affirmative	The revisions to the proposed FAC-003-2 Standards produced a better version through greater clarity, appropriate pragmatism, and technical foundation; A few good points that highlight this follow: 1. Definition of Terms Used in Standard: The revised definition of Right-of-Way (ROW) establishes the width of the corridor from a technical basis with the following

Voter	Entity	Segment	Vote	Comment
				statement "The width of the corridor is established by engineering or construction standards..." 2. Introduction, Applicability, Section 4.2 Facilities: Section 4.2.4 which pertains to substations clarifies that this standard does not apply to applicable transmission lines, inside the substation, just to "any portion of the span of the transmission line that is crossing the substation fence". 3. Requirements and Measures: Requirement 1 underscores sensible purpose by replacing the wording of "preventing outages from vegetation" to "manage vegetation to prevent encroachments..." 4. Guideline and Technical Basis Section: Requirement 7 contains a great practicle reference explanation as it pertains to the annual work plan. Requirement 7 explains: ..." the vegetation management approach should use the full extent of the Transmission Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management in the long term because it reduces the overall potential for encroachment, and it ensures that future planned work and future planned inspection cycles are sufficient".
Response: The SDT thanks you for your comments.				
Michael Ibold	Xcel Energy, Inc.	3	Affirmative	Xcel Energy still believes the requirement in R6 that mandates an annual inspection is an ineffective approach and may actually go against the Commission’s

Voter	Entity	Segment	Vote	Comment
				determination in FERC Order No. 693. The drafting team's response to our last round of comments on this issue was that "...the SDT was directed by Order 693 to set a minimum inspection criteria". It is clear in Order 693 that the Commission is not satisfied with allowing entities to choose their own inspection cycles, as the standard currently allows. However, we fail to see where the Commission mandated a minimum inspection cycle to be uniformly applied continent-wide. We urge the drafting team to revisit paragraphs 719 through 721 of Order 693. According to paragraph 721, the Commission recognizes that unique intervals by region, "based on local factors", are reasonable and appropriate. By use of the plural term "cycles", FERC anticipates the resolution may include multiple inspection cycles. Furthermore, in paragraph 719, FERC acknowledges that a minimum inspection cycle may not be the only way to address their concern. In fact, mandating an annual inspection cycle may actually go against the Commission's guidance in paragraph 720. Here is an excerpt: "...the Commission is dissuaded from requiring the ERO to create a backstop inspection cycle at this time. Instead, the Commission agrees that an entity's vegetation management program should be tailored to anticipated growth in the region and take into account other environmental factors. The goal is to assure that transmission owners conduct inspections at reasonable intervals." As an alternative, we propose a mid-cycle inspection. A mid-cycle inspection is based on an interval that is justified with data and technical expertise. A mid-cycle inspection would still require entities to conduct inspections at a specified interval, while allowing for differences based upon "physical

Voter	Entity	Segment	Vote	Comment
				and geographic factors". Not only would this approach fully address the Commissions concerns, but it would take into account the interests of stakeholders, landowners and rate-payers. We recognize that a mid-cycle inspection interval is not as easy to audit as an annual requirement, but it is a far more practical and cost-effective approach that, when applied based on an entity's expertise with its own facilities, ensures reliability.
Response: The SDT thanks you for your comments. The SDT recognizes that a number of Transmission Owners in North America may prefer to set their own inspection intervals. The SDT can also see attractiveness for a mid-cycle inspection concept; however, this introduces new complexities in planning, documentation and auditing. Because there is substantial industry support for an annual inspection interval the SDT believes that the industry is best served with this approach.				
Rick Syring	Cowlitz County PUD	4	Negative	Referring back to Cowlitz' negative vote made on the 7/9-19/2010 ballot, Cowlitz tried to convey the problem that the statement in R4 "without intentional time delay" will require subjective judgment on the part of the auditor. In other words, maintaining equal auditing standard throughout the interconnection will be impossible with this verbiage in a requirement. Cowlitz agrees with the SDT that establishing an equitable time frame is very difficult (it may be impossible!); however leaving it to the judgment of the auditor to determine whether an intentional delay was made is most disagreeable. Cowlitz respectfully points out that the SDT did not adequately address the subjective nature the auditor is forced into with this requirement. If "[t]he time required by the entity to report an issue is subject to many variables..." and "[f]or this reason it is difficult to establish a time period which would fairly apply to all TO's," how does leaving this to the auditor to decide going to make it any better? You will be forcing the audited entity to "prove the negative."

Voter	Entity	Segment	Vote	Comment
Response: The SDT believes that it was not prudent to suggest a quantitative time element for notification in R4. The technical reference offers examples of acceptable unintentional delays for your review. The SDT notes that this language is already embodied in at least one other FERC-approved, in-force Standard.				
Frank Gaffney	Florida Municipal Power Agency	4	Negative	R1 and R2 requirement reads: "Each Transmission Owner shall manage to prevent encroachment ....". The results of manage would be invoices of tree trimming actually performed, documentation of a vegetation management program that would be managed to, etc. However, the Measures proposed are all actual outages which are neither evidence of management nor evidence of encroachment since there can be encroachment without an outage, and in fact, many if not most encroachments do not result in outages. Hence, the Measures are inconsistent with the requirements. Further, there is ambiguity of the action required in requirements R1 and R2 - e.g., do entities need evidence that they: 1) "manage", or 2) "prevent encroachment"; or 3) as implied by the Measures, prevent vegetation related outages?. In other words, what needs to be proven through evidence? Certainly the third, prevent vegetation related outages, is not in the Requirement; yet, that us what is proposed for the Measures, highlighting the inconsistency between Requirements and Measures. But, how would the ambiguity between "manage" and "prevent encroachment" be resolved? One auditor could interpret that the requirement is to "manage" and accept a vegetation management program and plan and proof that the plan was executed as appropriate evidence. Another auditor could interpret that "prevent" is the key word and look for evidence proving that there was never a vegetation

Voter	Entity	Segment	Vote	Comment
				encroachment. How would evidence be produced to provide the auditor that vegetation never encroached? Would video cameras and other surveillance measures need to operate 24 hours a day? Would we cause an entity to survey the lines periodically? One can easily see that "prevent encroachment" is inappropriate here since it is infeasible to create evidence of compliance. FMPA suggests one of two approaches: Eliminate the word manage, but do not focus on encroachment and instead focus on outages. For instance: "Each Transmission Owner shall prevent vegetation related outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. Focus on the word "manage", similar to the existing FAC-003 standard, and move R3 to a new R1 to develop a management plan, and then the existing R1 and R2 become R2 an R3 and require execution of that plan in the words of R7, which would in turn enables elimination of R7.
Response: The SDT thanks you for your comments. In Order 693, FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.				
Thomas W. Richards	Fort Pierce Utilities	4	Negative	R1 and R2 requirement reads: "Each Transmission Owner shall manage to prevent encroachment ....". The results of

Voter	Entity	Segment	Vote	Comment
	Authority			manage would be invoices of tree trimming actually performed, documentation of a vegetation management program that would be managed to, etc. However, the Measures proposed are all actual outages which are neither evidence of management nor evidence of encroachment since there can be encroachment without an outage, and in fact, many if not most encroachments do not result in outages. Hence, the Measures are inconsistent with the requirements. Further, there is ambiguity of the action required in requirements R1 and R2 - e.g., do entities need evidence that they: 1) "manage", or 2) "prevent encroachment"; or 3) as implied by the Measures, prevent vegetation related outages?. In other words, what needs to be proven through evidence? Certainly the third, prevent vegetation related outages, is not in the Requirement; yet, that us what is proposed for the Measures, highlighting the inconsistency between Requirements and Measures. But, how would the ambiguity between "manage" and "prevent encroachment" be resolved? One auditor could interpret that the requirement is to "manage" and accept a vegetation management program and plan and proof that the plan was executed as appropriate evidence. Another auditor could interpret that "prevent" is the key word and look for evidence proving that there was never a vegetation encroachment. How would evidence be produced to provide the auditor that vegetation never encroached? Would video cameras and other surveillance measures need to operate 24 hours a day? Would we cause an entity to survey the lines periodically? One can easily see that "prevent encroachment" is inappropriate here since it is

Voter	Entity	Segment	Vote	Comment
				infeasible to create evidence of compliance. FPUA suggests one of two approaches: 1. Eliminate the word manage, but do not focus on encroachment and instead focus on outages. For instance: "Each Transmission Owner shall prevent vegetation related outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. 2. Focus on the word "manage", similar to the existing FAC-003 standard, and move R3 to a new R1 to develop a management plan, and then the existing R1 and R2 become R2 an R3 and require execution of that plan in the words of R7, which would in turn enables elimination of R7.
Response: The SDT thanks you for your comments. In Order 693, FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.				
Joseph G. DePoorter	Madison Gas and Electric Co.	4	Affirmative	"While supportive of the drafting team's efforts, The MGE believes a change is warranted in Footnote 2 and Footnote 4 to remove the exemption for "arboricultural activities or horticultural or agricultural activities" and replace with the term "installation of". As currently drafted, the wording could potentially be construed to mean that the TO would or could be constrained or refused permission to prune and remove any and all vegetation in the ROW in accordance

Voter	Entity	Segment	Vote	Comment
				with the full legal rights of the ROW agreement(s).”
Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.				
Douglas Hohlbaugh	Ohio Edison Company	4	Affirmative	FirstEnergy supports standard FAC-003-2 and would appreciate consideration of our comments submitted through the formal comment period.
Response: The SDT thanks you for your comments. Please see our consideration of your comments within the responses to the formal comments.				
Hao Li	Seattle City Light	4	Affirmative	The revisions to the proposed FAC-003-2 Standards produced a better version through greater clarity, appropriate pragmatism, and technical foundation; A few good points that highlight this follow: 1. Definition of Terms Used in Standard: The revised definition of Right-of-Way (ROW) establishes the width of the corridor from a technical basis with the following statement "The width of the corridor is established by engineering or construction standards..." 2. Introduction, Applicability, Section 4.2 Facilities: Section 4.2.4 which pertains to substations clarifies that this standard does not apply to applicable transmission lines, inside the substation, just to "any portion of the span of the transmission line that is crossing the substation fence". 3. Requirements and Measures: Requirement 1 underscores sensible purpose by replacing the wording of "preventing outages from vegetation" to "manage vegetation to prevent encroachments..."

Voter	Entity	Segment	Vote	Comment
				4. Guideline and Technical Basis Section: Requirement 7 contains a great practicle reference explanation as it pertains to the annual work plan. Requirement 7 explains: ..." the vegetation management approach should use the full extent of the Transmission Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management in the long term because it reduces the overall potential for encroachment, and it ensures that future planned work and future planned inspection cycles are sufficient".
Response: The SDT thanks you for your comments.				
Brock Ondayko	AEP Service Corp.	5	Affirmative	American Electric Power believes that the phrase "arboricultural activities or horticultural or agricultural activities" was mistakenly introduced into Footnotes 2 and 4, and should be deleted from both footnotes. If the phrase remains in the Standard, it may empower orchard growers, landowners and others to plant trees on the right of way and challenge Transmission Owners' rights to perform maintenance on the presumption that the standard will exempt the TO from violating the outage or encroachment requirements. For increased clarity, AEP offers the following change to the second paragraph of M1, as well as the second paragraph of M2. The original text “If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the

Voter	Entity	Segment	Vote	Comment
				equivalent of a Real-time observation" should be replaced with "If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation growing into or blowing together with the conductor within the ROW, this shall be considered the equivalent of a Real-time observation. A brief encroachment caused by falling vegetation passing through the MVCD is not considered an encroachment in this requirement".
Response: Thanks you for your comments. The SDT made suggested changes. Regarding the issue of fall-ins, the SDT is sympathetic to your concern. In fact, the SDT had originally crafted language similar to that which you suggested. However, due to concerns expressed by regulators and others, the exemption for encroachment violations due to falling vegetation from inside the right of way was removed.				
Francis J. Halpin	Bonneville Power Administration	5	Affirmative	In R1 and R2 and their associated VSLs, the SDT added the phrase "in order of increasing severity" and added the sentence, "The types of encroachments are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO's vegetation maintenance program." to the Rationale boxes for R1/R2. Do you agree? If answer is no, please explain. BPA prefers the stratified levels of violation severity presented in the table for R1 and R2. Foot note # 2 on page 8 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. Foot note # 4 on page 12 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities.

Voter	Entity	Segment	Vote	Comment
				In response to comments received that requirement R3 is unclear with respect to intent, the SDT added "maintenance strategies." Do you agree this clarifies the intent? If answer is no, please offer alternative language. The TO procedures / policies and specifications shall demonstrate the TO's ability to manage the system at all rated conditions to maintain reliability. BPA believes that the intent is clear, but the fundamental approach of using the MVCD (table 2) to manage a vegetation program is still problematic. These values are flashover distances and are way too close. This is acknowledged in a footnote to table 2 but no identification of allowable buffers/distances between energized phase conductors at rated temperatures and vegetation is discussed (this is left up the transmission owners). Clarity is needed on this topic. Setting a finite distance limit based on recognized standards, good science and risk avoidance should be done for the industry. BPA has previously made this comment during the drafting of the standard. It was not addressed then, nor has it been addressed now.
Response: The SDT thanks you for your comments. The footnotes were changed to conform with your suggestions. With respect to comments about the MVCD, R3 does not suggest the MVCD be used as a distance to manage vegetation. The MVCD was established as a beginning of a series of "building blocks" for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions. R3 requires that a Transmission Owner consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this "building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD distances.				

Voter	Entity	Segment	Vote	Comment
In a performance based standard, requirements are focused on “what” needs to be accomplished to achieve desired results and avoids prescriptive requirements of “how” to achieve that result. TO’s are in the best position to determine the appropriate management approach suited for their system rather than a “one size fits all” or “fill in the blanks” requirements that could suppress best practices for vegetation management.				
Wilket (Jack) Ng	Consolidated Edison Co. of New York	5	Affirmative	Reply to Question 5 on Comment Form: The added language for the annual work plan percentage complete calculation is shown in R7 not M7 as stated in the question. In the Guideline and Technical Basis Section for Requirement R6, there is a sample calculation shown for the amount of lines the TO failed to inspect. An example should also be included for Requirement R7 since there is some confusion regarding how modifications to the work plan affect the calculation. In the Lower VSL column for R7, it states that the TO failed to complete up to 5% of its annual vegetation work plan (including modifications if any). If a TO operates 100 lines and submits a justified modification that affects 10 miles of lines, the total number of units in the final amended plan is 90 miles. When you read the VSL, it is somewhat confusing since the information in parenthesis says that the calculation 'includes' the modifications. Should it state 'excludes modifications if any' or the VSLs can simply be re-written to state that ..The TO failed to complete up to x% of the final amended plan.' Also, the VSLs in R6 and R7 should be consistent with each other: R6 says '...TO failed to inspect 5% or less.....' and R7 says '...TO failed to complete up to 5%....' They both should use the same verbiage in each VSL whether it is 'x% or less' or 'up to and including x%.'

Voter	Entity	Segment	Vote	Comment
Response: The SDT thanks you for your comments. The percentage should be based on the plan as modified. The SDT has changed the language in the standard to reflect this more clearly, and has modified the VSLs to be consistent as you have suggested.				
James B Lewis	Consumers Energy	5	Negative	Consumers Energy submits the following comments on FAC-003-2: In general we are please with FAC-003-2 and the many clarifications that the STD has made in this version of the standard. However, we do have one major disagreement with the STD and cannot support this standard as drafted. We disagree with the use of the Minimum Vegetation Clearance Distance (MVCD) developed by the drafting team for Requirements R1 and R2. These distances are not the design distances used for designing and constructing transmission facilities as stated in the document for minimum distances between conductors and grounded objects. The proposed Table 2 provides a distance of 3.12 feet as the acceptable distance for an alternate current 345kV line at sea level. This distance is considerably less than the distance used for line design to separate the grounded tower structure from the energized conductor. If the distance in Table 2 is acceptable to prevent energized portions of a transmission line from grounding to a tree why then is this distance not the design criteria used for tower design to prevent flashover from conductor to tower? The STD needs to explain why a ground tree should have a different standard that a grounded steel tower or wood pole structure. The STD erroneously viewed the possibility of transient over

Voter	Entity	Segment	Vote	Comment
				voltage as only occurring during re-energizing and not from natural events such as a lightning strike that can occur and does occur to energized operating lines. Secondly, the proposed distances in Table 2 are considerably less than the distances specified in OSHA requirements for air gap clearance required by tree workers to safely remove trees or limbs from conductors energized at the voltages specified. A transmission owner/operator could let a tree grow to within 3.5 feet of a 345 kV line and not be in violation of this proposed standard. To remove the tree, the line would have to be de-energized, tagged, tested de-energized, and grounded. Working clearance would have to be established by the operating entity and then the tree crew could remove the tree. The net result is the loss of the capacity of the line because an outage was forced on the line in order to remove the tree that did not trigger a violation of FAC-003-2. This situation, in our opinion, is a violation of the intent of the standard, which is to ensure the continued operation of the line. Therefore, the minimum distance any tree should be able to approach a conductor is more than the minimum requirement for air gap distance between the tree and conductor as required by OSHA worker standards. The STD did not like referring to another standard to provide the distance requirements for R1 and R2. This can be alleviated by putting in a table with the IEEE 516 distances but not reference it as the IEEE 516 standard. The distances provided in the current draft do not adequately provide or ensure the continued safe operation of the transmission facilities in the United States and the reasoning for the distances provided is unfounded and not based on current design practices.

Voter	Entity	Segment	Vote	Comment
Response: The SDT thanks you for your comments. You are correct that these distances do not represent complete design specifications for towers, nor define and describe safe worker approach distances. These practices are correctly specified in the other standards you referenced. The SDT feels the standard is clear in that regard. The footnote associated with the Table 2 distances clearly states that these are only distances to prevent flashover under appropriate conditions. The SDT would also like to point out that the transient overvoltage factors used to derive these distances are the maximums normally seen with a transmission line in steady state service. Thus, a tower design would have to account for the larger overvoltage factors that are possible while taking lines out of service. As has been stated before, these distances were derived using a known set of line design equations and only represent distances that will prevent spark-over from the transmission line to a grounded object. These are not distances to be managed to – they have been established as a beginning of a series of "building blocks" for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions. R3 requires that a Transmission Owner consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this "building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD. These distances are smaller than safety standard distances that have many other factors involved in the determination, such as inadvertent human movement and larger safety factors. In regard to the over-voltages caused by lightning, even the maximum overvoltage factors contained in the IEEE-516 tables do not account for these.				
Bob Essex	Cowlitz County PUD	5	Negative	Referring back to Cowlitz' negative vote made on the 7/9-19/2010 ballot, Cowlitz tried to convey the problem that the statement in R4 "without intentional time delay" will require subjective judgment on the part of the auditor. In other words, maintaining equal auditing standard throughout the interconnection will be impossible with this verbiage in a requirement. Cowlitz agrees with the SDT that establishing an equitable time frame is very difficult (it may be impossible!); however leaving it to the judgment of the auditor to determine whether an intentional delay was made is most disagreeable. Cowlitz respectfully points out that the SDT did not adequately address the subjective nature the auditor is forced into with this requirement. If

Voter	Entity	Segment	Vote	Comment
				establishing "[t]he time required by the to report an issue is subject to many variables..." and "[f]or this reason it is difficult to establish a time period which would fairly apply to all TO's," how does leaving this to the auditor to decide going to make it any better?
Response: The SDT believes that it was not prudent to suggest a quantitative time element for notification in R4. The technical reference offers examples of acceptable unintentional delays for your review. The SDT notes that this language is already embodied in at least one other FERC-approved, in-force Standard.				
Kenneth Dresner	FirstEnergy Solutions	5	Affirmative	FirstEnergy supports standard FAC-003-2 and would appreciate consideration of our comments submitted through the formal comment period.
Response: The SDT thanks you for your comments. Please see our consideration of your comments within the responses to the formal comments.				
David Schumann	Florida Municipal Power Agency	5	Negative	R1 and R2 requirement reads: "Each Transmission Owner shall manage to prevent encroachment ....". The results of manage would be invoices of tree trimming actually performed, documentation of a vegetation management program that would be managed to, etc. However, the Measures proposed are all actual outages which are neither evidence of management nor evidence of encroachment since there can be encroachment without an outage, and in fact, many if not most encroachments do not result in outages. Hence, the Measures are inconsistent with the requirements. Further, there is ambiguity of the action required in requirements R1 and R2 - e.g., do entities need evidence that they: 1) "manage", or 2) "prevent encroachment"; or 3) as implied by the Measures, prevent vegetation related outages?. In other words, what needs to be proven through evidence? Certainly the third, prevent vegetation related

Voter	Entity	Segment	Vote	Comment
				outages, is not in the Requirement; yet, that us what is proposed for the Measures, highlighting the inconsistency between Requirements and Measures. But, how would the ambiguity between "manage" and "prevent encroachment" be resolved? One auditor could interpret that the requirement is to "manage" and accept a vegetation management program and plan and proof that the plan was executed as appropriate evidence. Another auditor could interpret that "prevent" is the key word and look for evidence proving that there was never a vegetation encroachment. How would evidence be produced to provide the auditor that vegetation never encroached? Would video cameras and other surveillance measures need to operate 24 hours a day? Would we cause an entity to survey the lines periodically? One can easily see that "prevent encroachment" is inappropriate here since it is infeasible to create evidence of compliance. FMPA suggests one of two approaches: Eliminate the word manage, but do not focus on encroachment and instead focus on outages. For instance: "Each Transmission Owner shall prevent vegetation related outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. Focus on the word "manage", similar to the existing FAC-003 standard, and move R3 to a new R1 to develop a management plan, and then the existing R1 and R2 become R2 an R3 and require execution of that plan in the words of R7, which would in turn enables elimination of R7.

Response: The SDT thanks you for your comments. In Order 693, FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines

Voter	Entity	Segment	Vote	Comment
how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.				
Richard J. Padilla	Pacific Gas and Electric Company	5	Affirmative	There needs to be a change in the footnotes 2 and 4 to remove the exemption for “arboricultural activities or horticultural or agricultural activities” and replace it with the term “ installation of"
Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.				
Wayne Lewis	Progress Energy Carolinas	5	Affirmative	There needs to be a change in the footnote 2 and footnote 4 to remove the exemption for “arboricultural activities or horticultural or agricultural activities” and replace it with the term “installation of.
Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.				
Liam Noailles	Xcel Energy, Inc.	5	Affirmative	Xcel Energy still believes the requirement in R6 that mandates an annual inspection is an ineffective approach and may actually go against the Commission’s determination in FERC Order No. 693. The drafting team’s response to our last round of comments on this issue was that “...the SDT was directed by Order 693 to set a minimum inspection criteria”. It is clear in Order 693 that the Commission is not satisfied with allowing entities to choose their own inspection cycles, as the standard currently allows. However, we fail to see where the Commission mandated a minimum inspection cycle to be uniformly applied continent-wide. We urge the drafting team to revisit paragraphs 719 through 721 of Order 693. According to paragraph 721, the Commission recognizes that unique intervals by region, “based on local factors”, are reasonable and appropriate. By use of the plural term “cycles”, FERC anticipates the resolution may include multiple inspection

Voter	Entity	Segment	Vote	Comment
				cycles. Furthermore, in paragraph 719, FERC acknowledges that a minimum inspection cycle may not be the only way to address their concern. In fact, mandating an annual inspection cycle may actually go against the Commission's guidance in paragraph 720. Here is an excerpt: "...the Commission is dissuaded from requiring the ERO to create a backstop inspection cycle at this time. Instead, the Commission agrees that an entity's vegetation management program should be tailored to anticipated growth in the region and take into account other environmental factors. The goal is to assure that transmission owners conduct inspections at reasonable intervals." As an alternative, we propose a mid-cycle inspection. A mid-cycle inspection is based on an interval that is justified with data and technical expertise. A mid-cycle inspection would still require entities to conduct inspections at a specified interval, while allowing for differences based upon "physical and geographic factors". Not only would this approach fully address the Commissions concerns, but it would take into account the interests of stakeholders, landowners and rate-payers. We recognize that a mid-cycle inspection interval is not as easy to audit as an annual requirement, but it is a far more practical and cost-effective approach that, when applied based on an entity's expertise with its own facilities, ensures reliability.
Response: The SDT thanks you for your comments. The SDT recognizes that a number of Transmission Owners in North America may prefer to set their own inspection intervals. The SDT can also see attractiveness for a mid-cycle inspection concept; however, this introduces new complexities in planning, documentation and auditing. Because there is substantial industry support for an annual inspection interval , the SDT believes that the industry is best served with this approach.				

Voter	Entity	Segment	Vote	Comment
Edward P. Cox	AEP Marketing	6	Affirmative	American Electric Power believes that the phrase "arboricultural activities or horticultural or agricultural activities" was mistakenly introduced into Footnotes 2 and 4, and should be deleted from both footnotes. If the phrase remains in the Standard, it may empower orchard growers, landowners and others to plant trees on the right of way and challenge Transmission Owners' rights to perform maintenance on the presumption that the standard will exempt the TO from violating the outage or encroachment requirements. For increased clarity, AEP offers the following change to the second paragraph of M1, as well as the second paragraph of M2. The original text "If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation" should be replaced with "If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation growing into or blowing together with the conductor within the ROW, this shall be considered the equivalent of a Real-time observation. A brief encroachment caused by falling vegetation passing through the MVCD is not considered an encroachment in this requirement".
Response: Thanks you for your comments. The SDT made the suggested changes to the footnotes. Regarding the issue of fall-ins, the SDT is sympathetic to your concern. In fact, the SDT had originally crafted language similar to that which you suggested. However, due to concerns expressed by regulators and others, the exemption for encroachment violations due to falling vegetation from inside the right of way was removed.				

Voter	Entity	Segment	Vote	Comment
Brenda S. Anderson	Bonneville Power Administration	6	Affirmative	BPA Comments with Yes Vote: In R1 and R2 and their associated VSLs, the SDT added the phrase “in order of increasing severity” and added the sentence, “The types of encroachments are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO’s vegetation maintenance program.” to the Rationale boxes for R1/R2. Do you agree? If answer is no, please explain. BPA prefers the stratified levels of violation severity presented in the table for R1 and R2. Foot note # 2 on page 8 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. Foot note # 4 on page 12 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. In response to comments received that requirement R3 is unclear with respect to intent, the SDT added “maintenance strategies.” Do you agree this clarifies the intent? If answer is no, please offer alternative language. The TO procedures / policies and specifications shall demonstrate the TO’s ability to manage the system at all rated conditions to maintain reliability. BPA believes that the intent is clear, but the fundamental approach of using the MVCD (table 2) to manage a vegetation program is still problematic. These values are

Voter	Entity	Segment	Vote	Comment
				flashover distances and are way too close. This is acknowledged in a footnote to table 2 but no identification of allowable buffers/distances between energized phase conductors at rated temperatures and vegetation is discussed (this is left up the transmission owners). Clarity is needed on this topic. Setting a finite distance limit based on recognized standards, good science and risk avoidance should be done for the industry. BPA has previously made this comment during the drafting of the standard. It was not addressed then, nor has it been addressed now.
Response: The SDT thanks you for your comments. The footnotes were changed to conform with your suggestions. With respect to comments about the MVCD, R3 does not suggest the MVCD be used as a distance to manage vegetation. The MVCD was established as a beginning of a series of "building blocks" for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions. R3 requires that a Transmission Owner consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this "building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD distances. In a performance based standard, requirements are focused on "what" needs to be accomplished to achieve desired results and avoids prescriptive requirements of "how" to achieve that result. TO's are in the best position to determine the appropriate management approach suited for their system rather than a "one size fits all" or "fill in the blanks" requirements that could suppress best practices for vegetation management.				
Matthew D Cripps	Cleco Power LLC	6	Negative	Cleco disagrees with the SDT revising the definition for Right-of-Way (ROW). Right-of-Way is a term that has had a consistent meaning throughout history. If NERC tries to redefine the term, it will only add confusion because most entities will not reference the NERC glossary for a term which is widely used in the industry. In lieu of "Active Transmission Line ROW", please use another term such as Transmission Corridor. No assumptions would be made when reading in the Standard the the Entity is to maintain

Voter	Entity	Segment	Vote	Comment
				vegetation located within the Transmission Corridor. Since the term is not commonly used, the NERC glossary would be referenced. Also, Cleco disagrees that an encroachment into the MCVD that does not cause an outage should be considered non-compliant as stated in R1 and R2. The encroachment should only be reportable similar to misoperations as is in the PRC-004 standard.
Response: Thanks for your comments. The existing ROW definition in the glossary was created by and for the FAC-003-1 and was moved there when that standard was adopted. The definition includes a series of options that give the Transmission Owner latitude in establishing ROW width. It does not require selecting a single method for its system. The term blowout standard is not capitalized and is not a defined term. This phrase in the definition allows a Transmission Owner to use its internal engineering standards or the general engineering standards that were in effect when the line was constructed to determine the ROW width. The SDT has limited the definition of Right-of-Way to a corridor of land with a defined width to operate a transmission line. This does not include danger tree rights. The definition of the MVCD is now added to this Standard. While use of the pre-2007 records is a compliance issue and is not in the purview of the SDT, it is the intent of the language in the definition that you could use this information. Regarding your second comment (begins with Also,): the MVCD was established as a beginning of a series of "building blocks" for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions. R3 requires that a Transmission Owner consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this "building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD. Other related requirements of this "Defense in Depth" Standard serve to address any number of scenarios which may arise or hinder the TO's ability to always strictly adhere to the management approach(s) established within R3. Thus the other requirements of this Standard provide the latitude for appropriate actions to remedy the condition without penalty. Further, trees which have encroached inside the MVCD are evidence of a deficiency in vegetation maintenance.				
Nickesha P Carrol	Consolidated Edison Co. of	6	Affirmative	Reply to Question 5 on Comment Form: The added language for the annual work plan percentage complete calculation is

Voter	Entity	Segment	Vote	Comment
	New York			shown in R7 not M7 as stated in the question. In the Guideline and Technical Basis Section for Requirement R6, there is a sample calculation shown for the amount of lines the TO failed to inspect. An example should also be included for Requirement R7 since there is some confusion regarding how modifications to the work plan affect the calculation. In the Lower VSL column for R7, it states that the TO failed to complete up to 5% of its annual vegetation work plan (including modifications if any). If a TO operates 100 lines and submits a justified modification that affects 10 miles of lines, the total number of units in the final amended plan is 90 miles. When you read the VSL, it is somewhat confusing since the information in parenthesis says that the calculation 'includes' the modifications. Should it state 'excludes modifications if any' or the VSLs can simply be re-written to state that ..The TO failed to complete up to x% of the final amended plan.'
Response: The SDT thanks you for your comments. The percentage should be based on the plan as modified. The SDT has changed the language in the standard to reflect this more clearly.				
Mark S Travaglianti	FirstEnergy Solutions	6	Affirmative	FirstEnergy supports standard FAC-003-2 and would appreciate consideration of our comments submitted through the formal comment period.
Response: The SDT thanks you for your comments. Please see our consideration of your comments within the responses to the formal comments.				
Thomas E Washburn	Florida Municipal Power Pool	6	Negative	The concern is that entities may not be able prove compliance with the standard. R1 and R2 say that: "Each Transmission Owner shall manage vegetation to prevent encroachments ...". If the requirements were interpreted such that "manage" is the operative word, then, we are OK because we can provide evidence of managing a program,

Voter	Entity	Segment	Vote	Comment
				such as a vegetation management plan and evidence of executing that plan (which does not align with the Measures). However, that 1) would cause the standard to not be performance based, and 2) it would be duplicative of the other requirements of the standard. If the requirements were interpreted with "prevent encroachment" as the operative phrase (which would be an incorrect interpretation from the construct of the sentence) there is no way to provide sufficient evidence that encroachment was prevented during the audit-period. The suggested Measures are not sufficient evidence to prove compliance with that interpretation of the requirement. For instance, most encroachments do not result in outages; hence, lack of outages cannot prove that there were no encroachments, and real time observations are insufficient because it is a spot-check that does not cover the audit period. There are other weaknesses in the standard, such as R4 being un-measurable therefore unenforceable. However, in the guilty until proven innocent paradigm we live in, FMPA's primary concern is that industry could be put into a no-win situation of not being able to prove compliance with the standard if R1 and R2 are interpreted as "prevent encroachment", and if R1 and R2 are interpreted as "manage" then it is not a performance based standard as advertised. Performance based focused on preventing vegetation related outages. For instance: "Each Transmission Owner

Voter	Entity	Segment	Vote	Comment
				shall prevent vegetation related outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. Modify the standard to be similar to the currently mandatory non-results based standard and focus on the word "manage". This would essentially mean eliminating R1 and R2 since the rest of the standard focuses on having a plan and managing to that plan..
Response: The SDT thanks you for your comments. In Order 693, FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.				
Silvia P. Mitchell	Florida Power & Light Co.	6	Affirmative	1. The SDT proposes a revised NERC Glossary definition for Right-of-Way (ROW). This revised definition will be used in lieu of the Active Transmission Line ROW. Do you agree? If answer is no, please explain. Yes 2. In R1 and R2 and their associated VSLs, the SDT added the phrase "in order of increasing severity" and added the sentence "The types of encroachments are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO's vegetation maintenance program." to the Rationale boxes for R1/R2. Do you agree? If answer is no, please explain. Yes Although NextEra Energy Inc. (NextEra), including Florida Power & Light Company, agrees with the changes referenced for R1

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				and R2, NextEra is concerned that the exemptions identified in footnote 2 for "...arboricultural activities or horticultural or agricultural activities...," and similar language in footnote 4, are too broad. For example, this language appears to include an exemption for a landowner, who, during arboricultural activities or horticultural or agricultural activities, causes a vegetation contact with a transmission line (e.g., cutting or lifting a tree into a transmission line). This places the Transmission Owner in the difficult position of a landowner arguing it is exempt from a controllable risk. Thus, the "...arboricultural activities or horticultural or agricultural activities..." references should be removed from footnote 2, and the similar language in footnote 4 3. In response to comments received regarding the term "investigation" in M1/M2, the SDT substituted "confirmation...by the Transmission Owner.." in its place, among other minor edits to these measures. Do you agree? If answer is no, please explain. Yes 4. In response to comments received that requirement R3 is unclear with respect to intent, the SDT added "maintenance strategies". Do you agree this clarifies the intent? If answer is no, please offer alternative language. Yes 5. The SDT added clarifying language in M7 to explain how the annual work plan percentage complete calculation is to be performed. Is this adequate? If no, please provide improved examples. Yes

Voter	Entity	Segment	Vote	Comment
Response: The SDT thanks you for your comments. The team has made the appropriate modifications to the footnotes as you suggested.				
Thomas Saitta	Kansas City Power & Light Co.	6	Negative	The Standard lacks clarity regarding the facilities that are subject to Requirement 7. It is important that a Standard be clear and not introduce ambiguity or confusion. There are several references throughout the Standard to "for all applicable lines" and it should be made clear the work plan is specific to "all applicable lines".
Response: The SDT thanks you for your comments. The phrase, "applicable lines" was added to R7 in support of your suggestion.				
Eric Ruskamp	Lincoln Electric System	6	Affirmative	While supportive of the drafting team's efforts, LES believes a change is warranted in Footnote 2 and Footnote 4 to remove the exemption for "arboricultural activities or horticultural or agricultural activities" and replace with the term "installation of". As currently drafted, the wording could potentially be construed to mean that the TO would or could be constrained or refused permission to prune and remove any and all vegetation in the ROW in accordance with the full legal rights of the ROW agreement(s).
Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.				
John T Sturgeon	Progress Energy	6	Affirmative	There needs to be a change in the footnote 2 and footnote 4 to remove the exemption for "arboricultural activities or horticultural or agricultural activities" and replace it with the term "installation of.
Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.				
David F. Lemmons	Xcel Energy, Inc.	6	Affirmative	Xcel Energy still believes the requirement in R6 that mandates an annual inspection is an ineffective approach and may actually go against the Commission's

Voter	Entity	Segment	Vote	Comment
				determination in FERC Order No. 693. The drafting team's response to our last round of comments on this issue was that "...the SDT was directed by Order 693 to set a minimum inspection criteria". It is clear in Order 693 that the Commission is not satisfied with allowing entities to choose their own inspection cycles, as the standard currently allows. However, we fail to see where the Commission mandated a minimum inspection cycle to be uniformly applied continent-wide. We urge the drafting team to revisit paragraphs 719 through 721 of Order 693. According to paragraph 721, the Commission recognizes that unique intervals by region, "based on local factors", are reasonable and appropriate. By use of the plural term "cycles", FERC anticipates the resolution may include multiple inspection cycles. Furthermore, in paragraph 719, FERC acknowledges that a minimum inspection cycle may not be the only way to address their concern. In fact, mandating an annual inspection cycle may actually go against the Commission's guidance in paragraph 720. Here is an excerpt: "...the Commission is dissuaded from requiring the ERO to create a backstop inspection cycle at this time. Instead, the Commission agrees that an entity's vegetation management program should be tailored to anticipated growth in the region and take into account other environmental factors. The goal is to assure that transmission owners conduct inspections at reasonable intervals." As an alternative, we propose a mid-cycle inspection. A mid-cycle inspection is based on an interval that is justified with data and technical expertise. A mid-cycle inspection would still require entities to conduct inspections at a specified interval, while allowing for differences based upon "physical

Voter	Entity	Segment	Vote	Comment
				and geographic factors". Not only would this approach fully address the Commissions concerns, but it would take into account the interests of stakeholders, landowners and rate-payers. We recognize that a mid-cycle inspection interval is not as easy to audit as an annual requirement, but it is a far more practical and cost-effective approach that, when applied based on an entity's expertise with its own facilities, ensures reliability.
Response The SDT thanks you for your comments. The SDT recognizes that a number of Transmission Owners in North America may prefer to set their own inspection intervals. The SDT can also see attractiveness for a mid-cycle inspection concept; however, this introduces new complexities in planning, documentation and auditing. Because there is substantial industry support for an annual inspection interval and due to the vastly simpler auditing associated with an annual interval, the SDT believes that the industry is best served with this approach.				
Jacquie Smith	ReliabilityFirst Corporation	10	Negative	ReliabilityFirst votes "No" on the proposed FAC-003-2 because ReliabilityFirst believes that the currently effective FAC-003-1, despite any weaknesses it may have, better ensures the reliability of the bulk electric system. First, under the proposed FAC-003-2, Requirements 1 and 2, the minimum clearances are reduced. Second, under the proposed structure of FAC-003-2, Requirements 1 and 2, violations would only occur where an encroachment of the Minimum Vegetation Clearance Distance ("MVCD") is observed in real time or after vegetation contact, i.e., after actual harm has occurred. Consequently, the proposed structure appears to convert a preventative maintenance standard into a standard that is essentially only violated after it is too late. The current structure from Version 1 of the standard (i.e., the Clearance

Voter	Entity	Segment	Vote	Comment
				1 and 2 requirements) better ensures reliability because they seek to ensure that registered entities discover problematic vegetation conditions prior to encroachments leading to flashover or vegetation contacts. For example, the current Clearance 1 is the "clearance distances to be achieved at the time of transmission vegetation management work." And the current Clearance 2 is the "specific radial clearances to be maintained under all rated electrical operating conditions." See FAC-003-1, R1.2.1 and R1.2.2 (emphasis added). Third, the draft standard appears to inappropriately and unnecessarily reduce the risk factor assigned to some failures to manage vegetation. It draws a distinction between those transmission lines that are elements of IROLs or Major Western Electricity Coordinating Council ("WECC") transfer paths and those that are not. This distinction is apparently based on the assumption that vegetation management violations on transmission lines that are not elements of IROLS or Major WECC transfer paths are less important. ReliabilityFirst disagrees with this assumption. Simply put, both are serious issues and the distinction is inappropriate and unnecessary. The Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, highlights the importance of all vegetation management work by identifying inadequate vegetation management as one of the causes of the 2003 Blackout. See Blackout Report, at p. 20. Finally, ReliabilityFirst disagrees with the proposed Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs")

Voter	Entity	Segment	Vote	Comment
				because they are premised on the same inappropriate and unnecessary distinction that vegetation management violations on transmission lines that are not elements of IROLS or Major WECC transfer paths are less important. For the foregoing reasons, ReliabilityFirst votes “No” on the proposed FAC-003-2.

Response: As with a Transmission Owner's determination of its Clearance 1 distances under version 1 of the Standard, Requirement 3 of the revised Standard begins with the MVCD distances (just as Clearance 1 began with IEEE-516 distances) and then requires additional consideration for conductor movement, vegetation growth variables, and the utility's maintenance approach. These are essentially the same considerations required by version 1 of the existing Standard when developing Clearance 1 distances. Therefore, nothing has been lost in the revised Standard.

The MVCD was established as a beginning of a series of “building blocks” for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions.

R3 requires that a Transmission Owner consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner’s overall vegetation management approach. The net result of this “building block” approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD distances.

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard. The draft, when taken in whole, does present a "preventative” maintenance standard.

The Standard has been designed utilizing a "Defense in Depth" strategy which provides for multiple layers of defense against a MVCD encroachment or an outage. These other layers of defense are identified in requirements R3 through R7. R3 through R7 are the same preventative maintenance requirements as contained in Version 1 of the Standards. Additionally, Measure 3 for R3 now tests the reasonableness and practicality of a TO’s vegetation management approach long before field work is implemented; other requirements such as R7 require preventative maintenance work to be completed before encroachments occur.

The SDT asserts that different VRF’s for IROL and non-IROL lines strengthens the reliability of the standard. Vegetation

Voter	Entity	Segment	Vote	Comment
managers that do not know which lines have IROLs or are designated as WECC Transfer Paths may be inappropriately limiting resources allocated to vegetation management for a line with an IROL or a line designated as a WECC Transfer Path. A vegetation manager must ensure that the lines with IROLs and lines designated as WECC transfer paths are absolutely clear. By correctly identifying the risk associated with lines with IROLs line and/or lines designated as WECC Transfer Paths, the standard helps to assure that appropriate resources are applied.				

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Non-binding Poll of VRFs and VSLs for FAC-003-2 (February 18-28, 2011) Consideration of Comments Report

Project 2007-07 Vegetation Management — September 30, 2011

Summary Consideration:

Some entities expressed concern regarding the use of the MVCD. The SDT explained that the MVCD was established as a beginning of a series of "building blocks" for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions, and that R3 requires that a Transmission Owner to consider the MVCD distances, as well as variables of conductor movement and the variables associated with vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this "building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD.

Other entities questioned if the intent of the standard is to "manage vegetation" or to "prevent outages. The STD responded that In Order 693, FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added).

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 404-446-2563 or via email at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
Gregory S Miller	Baltimore Gas & Electric Company	1	Affirmative	VRFs and VSLs seem reasonable.
Response: The SDT thanks you for your comments.				
Joseph S. Stonecipher	Beaches Energy Services	1	Negative	(See comments for 2007-07.)
Response: The SDT responded in the Successive Ballot Consideration of Comments document.				
Donald S. Watkins	Bonneville Power Administration	1	Affirmative	In R1 and R2 and their associated VSLs, the SDT added the phrase "in order of increasing severity" and added the sentence, "The types of encroachments are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO's vegetation maintenance program." to the Rationale boxes for R1/R2. Do you agree? If answer is no, please explain. BPA prefers the stratified levels of violation severity presented in the table for R1 and R2. Foot note # 2 on page 8 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. Foot note # 4 on page 12 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. In response to comments received that requirement R3 is unclear with respect to intent, the SDT added "maintenance strategies." Do you agree this clarifies the intent? If answer is no, please offer alternative language.

Voter	Entity	Segment	Vote	Comment
				The TO procedures / policies and specifications shall demonstrate the TO's ability to manage the system at all rated conditions to maintain reliability. BPA believes that the intent is clear, but the fundamental approach of using the MVCD (table 2) to manage a vegetation program is still problematic. These values are flashover distances and are way too close. This is acknowledged in a footnote to table 2 but no identification of allowable buffers/distances between energized phase conductors at rated temperatures and vegetation is discussed (this is left up the transmission owners). Clarity is needed on this topic. Setting a finite distance limit based on recognized standards, good science and risk avoidance should be done for the industry. BPA has previously made this comment during the drafting of the standard. It was not addressed then, nor has it been addressed now.
Response: The SDT thanks you for your comments. The footnotes were changed to conform with your suggestions. With respect to comments about the MVCD, R3 does not suggest the MVCD be used as a distance to manage vegetation. The MVCD was established as a beginning of a series of "building blocks" for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions. R3 requires that a Transmission Owner consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this "building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD. In a performance based standard, requirements are focused on "what" needs to be accomplished to achieve desired results and avoids prescriptive requirements of "how" to achieve that result. TO's are in the best position to determine the appropriate management approach suited for their system, rather than a "one size fits all" or "fill in the blank" requirement that could suppress best practices for vegetation management.				
Randall McCamish	City of Vero Beach	1	Negative	Vero Beach's concern is that entities may not be able prove compliance with the standard. R1 and R2 say that: "Each

Voter	Entity	Segment	Vote	Comment
				Transmission Owner shall manage vegetation to prevent encroachments ...". If the requirements were interpreted such that "manage" is the operative word, then, we are OK because we can provide evidence of managing a program, such as a vegetation management plan and evidence of executing that plan (which does not align with the Measures). However, that 1) would cause the standard to not be performance based, and 2) it would be duplicative of the other requirements of the standard. If the requirements were interpreted with "prevent encroachment" as the operative phrase (which would be an incorrect interpretation from the construct of the sentence) there is no way to provide sufficient evidence that encroachment was prevented during the audit-period. The suggested Measures are not sufficient evidence to prove compliance with that interpretation of the requirement. For instance, most encroachments do not result in outages; hence, lack of outages cannot prove that there were no encroachments, and real time observations are insufficient because it is a spot-check that does not cover the audit period. There are other weaknesses in the standard, such as R4 being un-measurable therefore unenforceable. However, in the guilty until proven innocent paradigm we live in, FMPA's primary concern is that industry could be put into a no-win situation of not being able to prove compliance with the standard if R1 and R2 are interpreted as "prevent encroachment", and if R1 and R2 are interpreted as "manage" then it is not a performance based standard as advertised. Vero Beach suggests one of two approaches: 1. Performance based focused on preventing vegetation

Voter	Entity	Segment	Vote	Comment
				related outages. For instance: "Each Transmission Owner shall prevent vegetation related outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. 2. Modify the standard to be similar to the currently mandatory non-results based standard and focus on the word "manage". This would essentially mean eliminating R1 and R2 since the rest of the standard focuses on having a plan and managing to that plan..
Response: The SDT thanks you for your comments. In Order 693, FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.				
Christopher L de Graffenried	Consolidated Edison Co. of New York	1	Affirmative	The VSLs in R6 and R7 should be consistent with each other: R6 says '...TO failed to inspect 5% or less.....' and R7 says '...TO failed to complete up to 5%....' They both should use the same verbiage in each VSL whether it is 'x% or less' or 'up to and including x%.'
Response: The SDT thanks you for your comments. The SDT has changed the verbiage in the VSLs in R6 and R7 such that it addresses you suggestion.				
Michael Gammon	Kansas City Power & Light Co.	1	Negative	The VSL for Requirement 7 should be clear and specifically state this specifically addresses only "all applicable lines".
Response: The SDT thanks you for your comments. The team has added the phrase, "applicable lines" as proposed to all the VSLs for R7.				
Stan T.	Keys Energy	1	Negative	Concern is that entities may not be able prove compliance with the standard. R1 and R2 say that: "Each Transmission

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Rzad	Services			Owner shall manage vegetation to prevent encroachments ...". If the requirements were interpreted such that "manage" is the operative word, then, we are OK because we can provide evidence of managing a program, such as a vegetation management plan and evidence of executing that plan (which does not align with the Measures). However, that 1) would cause the standard to not be performance based, and 2) it would be duplicative of the other requirements of the standard. If the requirements were interpreted with "prevent encroachment" as the operative phrase (which would be an incorrect interpretation from the construct of the sentence) there is no way to provide sufficient evidence that encroachment was prevented during the audit-period. The suggested Measures are not sufficient evidence to prove compliance with that interpretation of the requirement. For instance, most encroachments do not result in outages; hence, lack of outages cannot prove that there were no encroachments, and real time observations are insufficient because it is a spot-check that does not cover the audit period. There are other weaknesses in the standard, such as R4 being un-measurable therefore unenforceable. However, in the guilty until proven innocent paradigm we live in, FMPA's primary concern is that industry could be put into a no-win situation of not being able to prove compliance with the standard if R1 and R2 are interpreted as "prevent encroachment", and if R1 and R2 are interpreted as "manage" then it is not a performance based standard as advertised. one of two approaches are suggested: Performance based focused on preventing vegetation related outages. For instance: "Each Transmission Owner shall prevent vegetation related

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				outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. Modify the standard to be similar to the currently mandatory non-results based standard and focus on the word "manage". This would essentially mean eliminating R1 and R2 since the rest of the standard focuses on having a plan and managing to that plan..
Response: The SDT thanks you for your comments. In Order 693 FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.				
Walt Gill	Lake Worth Utilities	1	Negative	concern is that entities may not be able prove compliance with the standard. R1 and R2 say that: "Each Transmission Owner shall manage vegetation to prevent encroachments ...". If the requirements were interpreted such that "manage" is the operative word, then, we are OK because we can provide evidence of managing a program, such as a vegetation management plan and evidence of executing that plan (which does not align with the Measures). However, that 1) would cause the standard to not be performance based, and 2) it would be duplicative of the other requirements of the standard. If the requirements were interpreted with "prevent encroachment" as the operative phrase (which would be an incorrect interpretation from the construct of the sentence) there is no way to provide sufficient evidence that encroachment was prevented during the audit-period. The suggested Measures are not sufficient evidence to prove compliance

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				with that interpretation of the requirement. For instance, most encroachments do not result in outages; hence, lack of outages cannot prove that there were no encroachments, and real time observations are insufficient because it is a spot-check that does not cover the audit period. There are other weaknesses in the standard, such as R4 being un-measurable therefore unenforceable. However, in the guilty until proven innocent paradigm we live in, FMPA's primary concern is that industry could be put into a no-win situation of not being able to prove compliance with the standard if R1 and R2 are interpreted as "prevent encroachment", and if R1 and R2 are interpreted as "manage" then it is not a performance based standard as advertised. suggest one of two approaches: 1. Performance based focused on preventing vegetation related outages. For instance: "Each Transmission Owner shall prevent vegetation related outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. 2. Modify the standard to be similar to the currently mandatory non-results based standard and focus on the word "manage". This would essentially mean eliminating R1 and R2 since the rest of the standard focuses on having a plan and managing to that plan..
Response: The SDT thanks you for your comments. In Order 693 FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.				

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Marvin E VanBebber	Oklahoma Gas and Electric Co.	1	Negative	R3 VSL leaves a lot open to interpetation in the analysis area. This is one where the auditor could be heavy handed if he desired.
Response: The SDT thanks you for your comments. The Requirement 3 VSL does in fact give TO significant latitude with respect to maintaining appropriate clearances. As noted in the Rationale, "The documentation provides a basis for evaluating the competency of the Transmission Owner's vegetation program. There may be many acceptable approaches to maintain clearances." In a performance based standard, requirements (and associated VSLs) are focused on "what" needs to be accomplished to achieve desired results and avoids prescriptive requirements of "how" to achieve that result. TO's are in the best position to determine the appropriate management approach suited for their system rather than a "one-size-fits-all" requirement that could suppress best practices for vegetation management. With this in mind, if the TO is audited, and it has a well crafted vegetation management program and has properly documented procedures and results, it should be in a good position.				
Keith V Carman	Tri-State G & T Association, Inc.	1	Affirmative	There needs to be a change in the footnote 2 and footnote 4 to remove the exemption for "arboricultural activities or horticultural or agricultural activities" and replace it with the term " installation of".
Response: The SDT thanks you for your comments. The footnotes have been changed as proposed.				
Mark B Thompson	Alberta Electric System Operator	2	Abstain	VRFs and VSLs are set by Provincial authorities in Alberta.
Response: The SDT thanks you for your comments.				
David A. Lapinski	Consumers Energy	3	Negative	Comments on FAC-003-2 February 25, 2011 Consumers Energy submits the following comments on FAC-003-2: In general we are please with FAC-003-2 and the many clarifications that the STD has made in this version of the standard. However, we do have one major disagreement with the STD and cannot support this standard as drafted.

Voter	Entity	Segment	Vote	Comment
				We disagree with the use of the Minimum Vegetation Clearance Distance (MVCD) developed by the drafting team for Requirements R1 and R2. These distances are not the design distances used for designing and constructing transmission facilities as stated in the document for minimum distances between conductors and grounded objects. The proposed Table 2 provides a distance of 3.12 feet as the acceptable distance for an alternate current 345kV line at sea level. This distance is considerably less than the distance used for line design to separate the grounded tower structure from the energized conductor. If the distance in Table 2 is acceptable to prevent energized portions of a transmission line from grounding to a tree why then is this distance not the design criteria used for tower design to prevent flashover from conductor to tower? The STD needs to explain why a ground tree should have a different standard that a grounded steel tower or wood pole structure. The STD erroneously viewed the possibility of transient over voltage as only occurring during re-energizing and not from natural events such as a lightning strike that can occur and does occur to energized operating lines. Secondly, the proposed distances in Table 2 are considerably less than the distances specified in OSHA requirements for air gap clearance required by tree workers to safely remove trees or limbs from conductors energized at the voltages specified. A transmission owner/operator could let a tree grow to within 3.5 feet of a 345 kV line and not be in violation of this proposed standard. To remove the tree, the line would have to be de-energized, tagged, tested de-energized, and grounded. Working clearance would have to be established by the operating entity and then the tree crew could remove the

Voter	Entity	Segment	Vote	Comment
				tree. The net result is the loss of the capacity of the line because an outage was forced on the line in order to remove the tree that did not trigger a violation of FAC-003-2. This situation, in our opinion, is a violation of the intent of the standard, which is to ensure the continued operation of the line. Therefore, the minimum distance any tree should be able to approach a conductor is more than the minimum requirement for air gap distance between the tree and conductor as required by OSHA worker standards. The STD did not like referring to another standard to provide the distance requirements for R1 and R2. This can be alleviated by putting in a table with the IEEE 516 distances but not reference it as the IEEE 516 standard. The distances provided in the current draft do not adequately provide or ensure the continued safe operation of the transmission facilities in the United States and the reasoning for the distances provided is unfounded and not based on current design practices.
Response: The SDT thanks you for your comments. You are correct that these distances do not represent complete design specifications for towers, nor define and describe safe worker approach distances. These practices are correctly specified in the other standards you referenced. The SDT feels the standard is clear in that regard. The footnote associated with the Table 2 distances clearly states that these are only distances to prevent flashover under appropriate conditions. The SDT would also like to point out that the transient overvoltage factors used to derive these distances are the maximums normally seen with a transmission line in steady state service. Thus, a tower design would have to account for the larger overvoltage factors that are possible while taking lines out of service. As has been stated before, these distances were derived using a known set of line design equations and only represent distances that will prevent spark-over from the transmission line to a grounded object. These are not distances to be managed to – they have been established as a beginning of a series of "building blocks" for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions. R3 requires that a Transmission Owner' consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this				

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“building block” approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD. These distances are smaller than safety standard distances that have many other factors involved in the determination, such as inadvertent human movement and larger safety factors. In regard to the over-voltages caused by lightning, even the maximum overvoltage factors contained in the IEEE-516 tables do not account for these.				
Russell A Noble	Cowlitz County PUD	3	Negative	Referring back to Cowlitz’ negative vote made on the 7/9-19/2010 ballot, Cowlitz tried to convey the problem that the statement in R4 “without intentional time delay” will require subjective judgment on the part of the auditor. In other words, maintaining equal auditing standard throughout the interconnection will be impossible with this verbiage in a requirement. Cowlitz agrees with the SDT that establishing an equitable time frame is very difficult (it may be impossible!); however leaving it to the judgment of the auditor to determine whether an intentional delay was made is most disagreeable. Cowlitz respectfully points out that the SDT did not adequately address the subjective nature the auditor is forced into with this requirement. If establishing “[t]he time required by the to report an issue is subject to many variables...” and “[f]or this reason it is difficult to establish a time period which would fairly apply to all TO’s,” how does leaving this to the auditor to decide going to make it any better?
Response: The SDT thanks you for your comments. The SDT believes that it was not prudent to suggest a quantitative time element for notification in R4. The technical reference offers examples of acceptable unintentional delays for your review. The SDT notes that this language is already embodied in at least one other FERC-approved, in-force Standard.				
Charles Locke	Kansas City Power & Light Co.	3	Negative	The VSL for Requirement 7 should be clear and specifically state this specifically addresses only "all applicable lines".

Voter	Entity	Segment	Vote	Comment
Response: The SDT thanks you for your comments. The team has added the phrase, "applicable lines" as proposed to all the VSLs for R7.				
Mace Hunter	Lakeland Electric	3	Affirmative	R1. Each Transmission Owner shall manage vegetation to prevent encroachments of the types shown below, ---------------- and all Rated Electrical Operating Conditions.2 1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage, that is not corrected within 5 working days of discovery, Make the same change to R2 Type 1 encroachment and reflect the changes in Table 1. Rational: This condition would enable a entity to discover an encroachment and clear it without having to self report a possible violation as long as the conditions was corrected within 5 working days. The change should encourage extra inspections for problem areas more often than annually as required in R6. There should be no negative consequences for diligent inspection of lines as long as the problem is clear with a defined time such as 5 or 10 working days.
Response: The SDT thanks you for your comment. As a general rule, a revised standards should not be less stringent than the existing standard it replaces. In the existing standard, a violation occurs when the encroachment occurs. A 'find and fix' of five days would be viewed as a lowering the level of performance required by the current standard.				
Rick Syring	Cowlitz County PUD	4	Negative	Referring back to Cowlitz' negative vote made on the 7/9-19/2010 ballot, Cowlitz tried to convey the problem that the statement in R4 "without intentional time delay" will require subjective judgment on the part of the auditor. In other words, maintaining equal auditing standard throughout the interconnection will be impossible with this verbiage in a requirement. Cowlitz agrees with the SDT that establishing an equitable time frame is very difficult (it may be impossible!); however leaving it to the judgment of the

Voter	Entity	Segment	Vote	Comment
				auditor to determine whether an intentional delay was made is most disagreeable. Cowlitz respectfully points out that the SDT did not adequately address the subjective nature the auditor is forced into with this requirement. If “[t]he time required by the entity to report an issue is subject to many variables...” and “[f]or this reason it is difficult to establish a time period which would fairly apply to all TO’s,” how does leaving this to the auditor to decide going to make it any better? You will be forcing the audited entity to "prove the negative."
Response: The SDT thanks you for your comments. The SDT believes that it was not prudent to suggest a quantitative time element for notification in R4. The technical reference offers examples of acceptable unintentional delays for your review. The SDT notes that this language is already embodied in at least one other FERC-approved, in-force Standard.				
Frank Gaffney	Florida Municipal Power Agency	4	Negative	R1 and R2 requirement reads: "Each Transmission Owner shall manage to prevent encroachment ....". The results of manage would be invoices of tree trimming actually performed, documentation of a vegetation management program that would be managed to, etc. However, the Measures proposed are all actual outages which are neither evidence of management nor evidence of encroachment since there can be encroachment without an outage, and in fact, many if not most encroachments do not result in outages. Hence, the Measures are inconsistent with the requirements. Further, there is ambiguity of the action required in requirements R1 and R2 - e.g., do entities need evidence that they: 1) "manage", or 2) "prevent encroachment"; or 3) as implied by the Measures, prevent vegetation related outages?. In other words, what needs to be proven through evidence? Certainly the third, prevent vegetation related outages, is not in the Requirement; yet, that us what is proposed for the Measures, highlighting the

Voter	Entity	Segment	Vote	Comment
				inconsistency between Requirements and Measures. But, how would the ambiguity between "manage" and "prevent encroachment" be resolved? One auditor could interpret that the requirement is to "manage" and accept a vegetation management program and plan and proof that the plan was executed as appropriate evidence. Another auditor could interpret that "prevent" is the key word and look for evidence proving that there was never a vegetation encroachment. How would evidence be produced to provide the auditor that vegetation never encroached? Would video cameras and other surveillance measures need to operate 24 hours a day? Would we cause an entity to survey the lines periodically? One can easily see that "prevent encroachment" is inappropriate here since it is infeasible to create evidence of compliance. FMPA suggests one of two approaches: Eliminate the word manage, but do not focus on encroachment and instead focus on outages. For instance: "Each Transmission Owner shall prevent vegetation related outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. Focus on the word "manage", similar to the existing FAC-003 standard, and move R3 to a new R1 to develop a management plan, and then the existing R1 and R2 become R2 an R3 and require execution of that plan in the words of R7, which would in turn enables elimination of R7.
Response: The SDT thanks you for your comments. In Order 693 FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation"** (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct				

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inspections in which clearances are evaluated.				
Douglas Hohlbaugh	Ohio Edison Company	4	Affirmative	For the Requirement R1 and R2 VSLs, we suggest that the proposed Moderate (fall-ins) and High (blowing together) VSL be interchanged. We believe that fall-ins are more severe encroachments than blowing together and the categories listed in the compliance section support this point. Category 1 (grow-ins) is most severe, followed by Category 2 & 3 (fall-ins) and Category 4 (blowing together. If the team elects to not make the suggested VSL changes then a change in the category listing within the compliance section is warranted. Either way they should be consistent.
Response: The SDT believes that there is consensus that "blowing-together" events are more indicative of a program failure than are "fall-in" events. Further, the risk to the transmission system from blowing-together events is greater than for fall-ins; partly because blowing-together events are more likely to repeat themselves, whereas fall-ins generally end on the spot. The SDT agrees with you that the ordering of the categories seems to convey a different message; however, re-sequencing the categories in order of severity would have led to a clash with the existing categories in Version 1 and thus would have provoked widespread confusion.				
Francis J. Halpin	Bonneville Power Administration	5	Affirmative	In R1 and R2 and their associated VSLs, the SDT added the phrase "in order of increasing severity" and added the sentence, "The types of encroachments are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO's vegetation maintenance program." to the Rationale boxes for R1/R2. Do you agree? If answer is no, please explain. BPA prefers the stratified levels of violation severity presented in the table for R1 and R2. Foot note # 2 on page 8 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities.

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				Foot note # 4 on page 12 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. In response to comments received that requirement R3 is unclear with respect to intent, the SDT added "maintenance strategies." Do you agree this clarifies the intent? If answer is no, please offer alternative language. The TO procedures / policies and specifications shall demonstrate the TO's ability to manage the system at all rated conditions to maintain reliability. BPA believes that the intent is clear, but the fundamental approach of using the MVCD (table 2) to manage a vegetation program is still problematic. These values are flashover distances and are way too close. This is acknowledged in a footnote to table 2 but no identification of allowable buffers/distances between energized phase conductors at rated temperatures and vegetation is discussed (this is left up the transmission owners). Clarity is needed on this topic. Setting a finite distance limit based on recognized standards, good science and risk avoidance should be done for the industry. BPA has previously made this comment during the drafting of the standard. It was not addressed then, nor has it been addressed now.
Response: The SDT thanks you for your comments. The footnotes were changed to conform with your suggestions. With respect to comments about the MVCD, R3 does not suggest the MVCD be used as a distance to manage vegetation. The MVCD was established as a beginning of a series of "building blocks" for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions. R3 requires that a Transmission Owner consider the MVCD distances, as well as variables of conductor movement and				

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vegetation growth, when designing the Transmission Owner's overall vegetation management approach. The net result of this "building block" approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD distances. In a performance based standard, requirements are focused on "what" needs to be accomplished to achieve desired results and avoids prescriptive requirements of "how" to achieve that result. TO's are in the best position to determine the appropriate management approach suited for their system rather than a "one size fits all" requirements that could suppress best practices for vegetation management.				
James B Lewis	Consumers Energy	5	Negative	See comments on the Standard.
Response: The SDT thanks you for your comments that were made during the formal comment period for the Standard; the SDT's responses to those comments are available there.				
Bob Essex	Cowlitz County PUD	5	Negative	Referring back to Cowlitz' negative vote made on the 7/9-19/2010 ballot, Cowlitz tried to convey the problem that the statement in R4 "without intentional time delay" will require subjective judgment on the part of the auditor. In other words, maintaining equal auditing standard throughout the interconnection will be impossible with this verbiage in a requirement. Cowlitz agrees with the SDT that establishing an equitable time frame is very difficult (it may be impossible!); however leaving it to the judgment of the auditor to determine whether an intentional delay was made is most disagreeable. Cowlitz respectfully points out that the SDT did not adequately address the subjective nature the auditor is forced into with this requirement. If establishing "[t]he time required by the to report an issue is subject to many variables..." and "[f]or this reason it is difficult to establish a time period which would fairly apply to all TO's," how does leaving this to the auditor to decide going to make it any better?

Voter	Entity	Segment	Vote	Comment
Response: The SDT thanks you for your comments. The SDT believes that it was not prudent to suggest a quantitative time element for notification in R4. The technical reference offers examples of acceptable unintentional delays for your review. The SDT notes that this language is already embodied in at least one other FERC-approved, in-force Standard.				
David Schumann	Florida Municipal Power Agency	5	Negative	R1 and R2 requirement reads: "Each Transmission Owner shall manage to prevent encroachment ....". The results of manage would be invoices of tree trimming actually performed, documentation of a vegetation management program that would be managed to, etc. However, the Measures proposed are all actual outages which are neither evidence of management nor evidence of encroachment since there can be encroachment without an outage, and in fact, many if not most encroachments do not result in outages. Hence, the Measures are inconsistent with the requirements. Further, there is ambiguity of the action required in requirements R1 and R2 - e.g., do entities need evidence that they: 1) "manage", or 2) "prevent encroachment"; or 3) as implied by the Measures, prevent vegetation related outages?. In other words, what needs to be proven through evidence? Certainly the third, prevent vegetation related outages, is not in the Requirement; yet, that us what is proposed for the Measures, highlighting the inconsistency between Requirements and Measures. But, how would the ambiguity between "manage" and "prevent encroachment" be resolved? One auditor could interpret that the requirement is to "manage" and accept a vegetation management program and plan and proof that the plan was executed as appropriate evidence. Another auditor could interpret that "prevent" is the key word and look for evidence proving that there was never a vegetation encroachment. How would evidence be produced to provide the auditor that vegetation never encroached?

Voter	Entity	Segment	Vote	Comment
				Would video cameras and other surveillance measures need to operate 24 hours a day? Would we cause an entity to survey the lines periodically? One can easily see that "prevent encroachment" is inappropriate here since it is infeasible to create evidence of compliance. FMPA suggests one of two approaches: Eliminate the word manage, but do not focus on encroachment and instead focus on outages. For instance: "Each Transmission Owner shall prevent vegetation related outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. Focus on the word "manage", similar to the existing FAC-003 standard, and move R3 to a new R1 to develop a management plan, and then the existing R1 and R2 become R2 an R3 and require execution of that plan in the words of R7, which would in turn enables elimination of R7.
Response: The SDT thanks you for your comments. In Order 693 FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.				
Brenda S. Anderson	Bonneville Power Administration	6	Affirmative	BPA Comments with Yes Vote: In R1 and R2 and their associated VSLs, the SDT added the phrase "in order of increasing severity" and added the sentence, "The types of encroachments are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO's vegetation maintenance program." to the Rationale boxes for R1/R2. Do you agree? If answer is no, please explain. BPA prefers the stratified levels of violation severity

Voter	Entity	Segment	Vote	Comment
				presented in the table for R1 and R2. Foot note # 2 on page 8 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. Foot note # 4 on page 12 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. In response to comments received that requirement R3 is unclear with respect to intent, the SDT added "maintenance strategies." Do you agree this clarifies the intent? If answer is no, please offer alternative language. The TO procedures / policies and specifications shall demonstrate the TO's ability to manage the system at all rated conditions to maintain reliability. BPA believes that the intent is clear, but the fundamental approach of using the MVCD (table 2) to manage a vegetation program is still problematic. These values are flashover distances and are way too close. This is acknowledged in a footnote to table 2 but no identification of allowable buffers/distances between energized phase conductors at rated temperatures and vegetation is discussed (this is left up the transmission owners). Clarity is needed on this topic. Setting a finite distance limit based on recognized standards, good science and risk avoidance should be done for the industry. BPA has previously made this comment during the drafting of the standard. It was not addressed then, nor has it been addressed now.
Response: The SDT thanks you for your comments. The footnotes were changed to conform with your suggestions. With respect to comments about the MVCD, R3 does not suggest the MVCD be used as a distance to manage vegetation. The MVCD				

Voter	Entity	Segment	Vote	Comment
was established as a beginning of a series of “building blocks” for a program to ensure reliability of a Transmission line within its rating and all rated electrical operating conditions. R3 requires that a Transmission Owner’ consider the MVCD distances, as well as variables of conductor movement and vegetation growth, when designing the Transmission Owner’s overall vegetation management approach. The net result of this “building block” approach is that when entities implement R7, their efforts will result in vegetation management at clearance distances greater than the MVCD distances. In a performance based standard, requirements are focused on “what” needs to be accomplished to achieve desired results and avoids prescriptive requirements of “how” to achieve that result. TO’s are in the best position to determine the appropriate management approach suited for their system rather than a “one size fits all” requirement that could suppress best practices for vegetation management.				
Nickesha P Carrol	Consolidated Edison Co. of New York	6	Affirmative	The VSLs in R6 and R7 should be consistent with each other: R6 says '...TO failed to inspect 5% or less.....' and R7 says '...TO failed to complete up to 5%....' They both should use the same verbiage in each VSL whether it is 'x% or less' or 'up to and including x%.'
Response: The SDT thanks you for your comments. The SDT has changed the verbiage in the VSLs in R6 and R7 such that it addresses you suggestion.				
Mark S Travaglianti	FirstEnergy Solutions	6	Affirmative	FirstEnergy supports standard FAC-003-2 and would appreciate consideration of our comments submitted through the formal comment period.
Response: The SDT thanks you for your comments and has reviewed and responded to your comments made during the formal comment period.				
Thomas E Washburn	Florida Municipal Power Pool	6	Negative	The concern is that entities may not be able prove compliance with the standard. R1 and R2 say that: "Each Transmission Owner shall manage vegetation to prevent encroachments ...". If the requirements were interpreted such that "manage" is the operative word, then, we are OK because we can provide evidence of managing a program, such as a vegetation management plan and evidence of

Voter	Entity	Segment	Vote	Comment
				executing that plan (which does not align with the Measures). However, that 1) would cause the standard to not be performance based, and 2) it would be duplicative of the other requirements of the standard. If the requirements were interpreted with "prevent encroachment" as the operative phrase (which would be an incorrect interpretation from the construct of the sentence) there is no way to provide sufficient evidence that encroachment was prevented during the audit-period. The suggested Measures are not sufficient evidence to prove compliance with that interpretation of the requirement. For instance, most encroachments do not result in outages; hence, lack of outages cannot prove that there were no encroachments, and real time observations are insufficient because it is a spot-check that does not cover the audit period. There are other weaknesses in the standard, such as R4 being un-measurable therefore unenforceable. However, in the guilty until proven innocent paradigm we live in, FMPA's primary concern is that industry could be put into a no-win situation of not being able to prove compliance with the standard if R1 and R2 are interpreted as "prevent encroachment", and if R1 and R2 are interpreted as "manage" then it is not a performance based standard as advertised. Performance based focused on preventing vegetation related outages. For instance: "Each Transmission Owner shall prevent vegetation related outages (except as noted in Footnote 2) of any of its applicable line(s) ..." Evidence of outages is practical to gather and provide, evidence of encroachment is not. Modify the standard to be similar to the currently mandatory non-results based standard and focus on the word "manage". This would essentially mean eliminating R1

Voter	Entity	Segment	Vote	Comment
				and R2 since the rest of the standard focuses on having a plan and managing to that plan..
Response: The SDT thanks you for your comments. In Order 693 FERC was very specific that "…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**" (emphasis added). The drafting team followed that concept and used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. Item 1 in the requirements defines how an encroachment without an outage would be documented. Each Transmission Owner is also required to conduct inspections in which clearances are evaluated.				
Thomas Saitta	Kansas City Power & Light Co.	6	Negative	The VSL for Requirement 7 should be clear and specifically state this specifically addresses only "all applicable lines".
Response: The SDT thanks you for your comments. The team has added the phrase, "applicable lines" as proposed to all the VSLs for R7.				
James Eckelkamp	Progress Energy	6	Affirmative	There needs to be a change in the footnote 2 and footnote 4 to remove the exemption for "arboricultural activities or horticultural or agricultural activities" and replace it with the term "installation of."
Response: The SDT thanks you for your comments. The changes to the footnotes have been made as proposed.				
Guy V. Zito	Northeast Power Coordinating Council, Inc.	10	Affirmative	The use of the term "encroachment", and the lack of clarity in defining clearances is an issue that should be addressed by the Drafting Team.
Response: The SDT thanks you for your comments. With regard to the use of "encroachment" and the clarity in defining clearances as it relates to the VRFs and VSLs, the SDT has taken what was a "gray" area in Version 1 and added more clarity with regard to compliance. In Version 1, it is not actually clear whether experiencing an encroachment or experiencing outage is a violation of the standard. The SDT recognized this concern and has addressed this via the proposed VSLs for R1 and R2. These proposed VSLs are designed such to correlate to the severity level of failure of the Transmission Owner's vegetation management program.				

Voter	Entity	Segment	Vote	Comment
If you refer to the VSLs for R1 and R2, only the "Lower" VSLs apply to an encroachment, and that has been defined as "an encroachment into the MVCD observed in Real-time, absent a Sustained Outage." The "MVCD" clearance distance is clearly defined in Table 2 of the Standard. After the Lower VSL level for these requirements, the Moderate to Severe VSLs are correlated more directly to the severity of failure of the Transmission Owner's vegetation management program associated with a Sustained Outage. The SDT makes this recommendation of VSLs based on this being an improvement for compliance clarity over version 1 of the standard.				
Anthony E Jablonski	ReliabilityFirst Corporation	10	Negative	ReliabilityFirst votes negative and has the following comments regarding the VRFs and VSLs: 1. VRF for R1 and R2 a. The Final Report on the August 14th, 2003 Blackout in the United States and Canada: Causes and Recommendations Blackout Report, highlights the importance of all vegetation management work by identifying inadequate vegetation management as one of the causes of the 2003 Blackout. Based on the Blackout Report there should be no distinction between encroachments of applicable line(s) identified as an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path(s) and encroachments of applicable line(s) not identified as an element of an Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path(s). Therefore, ReliabilityFirst recommends that VRFs should be the same for R1 and R2. 2. VSL for R3 a. Since this requirement has sub-parts associated with it, the associated sub-part number should be referenced in the VSL itself.

Voter	Entity	Segment	Vote	Comment
				3. VSL for R4 a. The words in the VLS do not match the language in the requirement. The words “vegetation threat” is not mentioned in Requirement R4. Based on the FERC Guideline #3 “Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement” 4. VSL for R6 a. The following qualifier should be added to the end of each of the four VSLs, “...at least once per calendar year and with no more than 18 months between inspections on the same ROW” to be consistent with the corresponding requirement and in accordance with the FERC Guideline #3. 5. VSL for R7 a. There is no associated VSL dealing with the second part of the requirement which references that “... the Modifications to the work plan... must be documented.” Where does an entity fall if they have complete 100% of its annual vegetation work plan, but failed to document any modifications to the work plan? This aspect of the requirement should be addressed in the corresponding VSLs.

Response: The SDT thanks you for your comments.

1) In Order 693 FERC was very specific that “…FAC-003-1 is designed to minimize transmission outages from vegetation located on or near transmission rights-of-way **by maintaining safe clearances between transmission lines and vegetation**” (emphasis added). Following that concept, the SDT used R1 and R2 to move the clearance from a documentation requirement to a performance requirement. .

R1 and R2 are dealing with the differentiation between lines that fall into an IROL or WECC Transfer Path definition and those lines that do not. The SDT asserts that different VRF’s for IROL and non-IROL lines strengthens the reliability of the standard. Vegetation managers that do not know which lines are IROL or WECC Transfer Paths may be inappropriately limiting resources allocated to vegetation management for an IROL line or a WECC Transfer Path. A vegetation manager must ensure that the

Voter	Entity	Segment	Vote	Comment
IROL lines and WECC transfer paths are absolutely clear. By correctly identifying the risk associated with an IROL line and/or a WECC Transfer Path, the standard helps to assure that appropriate resources are applied. 2) The sub-parts referred to are part of the RBS building block approach to document how a TO prevents encroachment of vegetation into the MVCD. The sub parts are not separate elements but make up the processes, strategies, procedures or specifications to prevent encroachment in to the MVCD. 3) The SDT believes the correlation between R4 and the VSL is appropriate. 4) The SDT believes the correlation between R6 and the VSL is appropriate. 5) The wording in the VSL for R7 has been modified to address modifications to the annual work plan.				

Consideration of Comments on Draft 5 of FAC-003-2

Project 2007-07 Vegetation Management — September 30, 2011

Background
The Transmission Vegetation Management Drafting Team thanks all commenters who submitted comments on the 5th Draft of FAC-003-2 Transmission Vegetation Management standards. These standards were posted for a 30-day public comment period from January 27, 2011 through February 28, 2011. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 41 sets of comments, including comments from more than 106 different people from approximately 63 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

Summary of Changes
In order to be consistent with the latest version of NERC's Results Based Standards template, the heading "Objective" was replaced with "Purpose," and the numbering, headings, and sections were reformatted as necessary.

One repeated concern was whether or not "danger trees" rights outside the Right-of-Way (ROW) should be an extension of the ROW. The SDT has limited the definition of Right-of-Way to a corridor of land with a defined width to operate a transmission line, which does not include danger tree rights.

Another repeated concern was reference to the term "blowout standard" and commenters were asking for more clarification and/or a specific definition of that term. To this line of comments the SDT responded, "the definition includes a series of options that give the Transmission Owner latitude in establishing ROW width. It does not require selecting a single method for its system. The term blowout standard is not capitalized and is not a defined term, and is intended to represent whatever conductor "blow out" (as opposed to vegetation "blow in") design criteria were used when the line was constructed. This phrase in the definition allows a Transmission Owner to use its internal engineering standards or the general engineering standards that were in effect when the line was constructed to determine the ROW width."

A request was made to include the definition of MVCD within the definition section of the standard. The SDT agreed with the commenter's request and used the appropriate portion of the existing language in the rationale text box associated with R1 for the MVCD definition. The SDT understands that this term will be added to the NERC glossary coincident with this standard becoming effective. This is not a substantive change to the standard, it is merely procedural.

The SDT made minor changes to the footnotes in response to several requests.

There was some concern expressed regarding the relationships between the VSLs and language in the requirements. The SDT revised the language in the Rationale box to explain the program performance relationships between types of encroachments, faults and outages, and various types of failed maintenance, and how the various types of failed maintenance have historically been associated with known vegetation related events.

One commenter requested that “of applicable lines” be added to the requirements and VSL verbiage to clearly denote applicability within the requirements and VSL verbiage. The SDT made those changes as requested to the requirements, measures and VSLs.

Two commenters requested an example be added to the Guidelines and Technical Basis similar to the examples in R6 to clarify that the % calculations should be based on the Annual Plan as modified; the SDT added the example as requested.

http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 404-446-2563 or via email at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.1

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/standards/newstandardsprocess.html.

NERC

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Joe Spencer	SERC Vegetation Management sub-committee										X
2.	Group	Sasa Maljukan	Hydro One Networks	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Fatima Ahmed	SEPA	SERC	
2.	Gerry Beckerie	Ameren	SERC	
3.	Todd Bennett	AECI	SERC	
4.	Brent Davis	Entergy	SERC	
5.	Richard Dearman	TVA	SERC	
6.	Jack Gardner	Progress Energy	SERC	
7.	Jeff Hackman (chair)	Ameren	SERC	
8.	Ralph Hale	Entergy	SERC	
9.	Jerry Lindler	SCANA	SERC	
10.	Larry Rodriguez	Entegra Power	SERC	
11.	Joe Spencer	SERC Reliability	SERC	
12.	John Troha	SERC Reliability	SERC	
13.	Marc Tunstall	Fayetteville Public Works Com	SERC	
14.	Terry Wilson	Power South	SERC	

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Kiguel	Hydro One Networks Inc	NPCC	1
2.	Jonathan Marriott	Hydro One Networks Inc.		1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Bohdan M. Dackow	US Power Generating Company (USPG)	NPCC	NA
6.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
7.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
8.	Brian Evans-Mongeon	Utility Services	NPCC	8
9.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
10.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	David Kiguel	Hydro One Networks Inc.	NPCC	1
13.	Michael R. Lombardi	Northeast Utilities	NPCC	1
14.	Randy MacDonald	New Brunswick Power Transmission	NPCC	1
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Chantel Haswell	FPL Group, Inc.	NPCC	5
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Saurabh Saksena	National Grid	NPCC	1
20.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Deborah Schaneman	Platte River Power Authority Substation Maintenance Group	X		X		X	X				

Additional Member	Additional Organization	Region	Segment

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

				Selection
1.	Scott Rowley	Platte River Power Authority	WECC	1, 3, 5, 6
2.	Gary Whittenberg	Platte River Power Authority	WECC	1, 3, 5, 6
3.	Aaron Johnson	Platte River Power Authority	WECC	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
5.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charles Sheppard	BPA, Transmission Field Services	WECC	1
2.	Steven Narolski	BPA, Transmission Field Services	WECC	1
3.	Frank Weintraub	BPA, Transmission Lign Design	WECC	1
4.	Jennifer Bailey	BPA, Transmission, Construction Mgmt and Inspect	WECC	1
5.	Don Swanson	BPA, Transmission TLM Technical Services	WECC	1
6.	Steve Bottemiller	BPA, Transmission, Real Property Support Svcs	WECC	1
7.	Vince Ierulli	BPA, Transmission Lign Design	WECC	1
8.	Mike Staats	BPA, Transmission Engineering	WECC	1
9.	Jenifur Rancourt	BPA, FERC Compliance	WECC	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
6.	Group	Doug Keegan	NERC Staff										
7.	Group	David Thorne	Pepco Holdings Inc and Affiliates	X		X							

Additional Member	Additional Organization	Region	Segment Selection	
1.	Dana Small		RFC	1
2.	Lisa E Pfeifer		RFC	1
3.	Pat J Byrne		RFC	1

				1	2	3	4	5	6	7	8	9	10
8.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rebecca Spach	FE	RFC	1
2.	Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6
3.	Dave Folk	FE	RFC	1, 3, 4, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
4.	Mike Ferncez	FE	RFC	1
5.	Shawn Standish	FE	RFC	1
6.	Katrina Schnobrich	FE	RFC	

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Mike Garton	Dominion Electric Market Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Michael Gildea	Dominion Resources Services, Inc.	NPCC	5
2.	Louis Slade	Dominion Resources Services, Inc.	SERC	5
3.	Connie Lowe	Dominion Resources Services, Inc.	RFC	6
4.	Michael Crowley	Dominion Virginia Power	SERC	1, 3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Individual	JT Wood	Southern Company Transmission	X		X							
11.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
12.	Individual	Cynthia Oder	Salt River Project	X		X		X	X				
13.	Individual	Luke Diruzza	Tampa Electric Company	X		X		X	X				
14.	Individual	Silvia Parada Mitchell	NextEra Energy	X		X		X	X				
15.	Individual	Jennifer Wright	SDG&E	X		X		X					
16.	Individual	JAMES SMITH	ASSET MANAGEMENET	X									
17.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie (NCR07112)	X									
18.	Individual	Michael Gammon	Kansas City Power & Light	X		X		X	X				
19.	Individual	Joe Petaski	Manitoba Hydro	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
20.	Individual	Weston Davis	Central Maine Power Company - IberdrolaUSA	X									
21.	Individual	Gordon Rawlings	BC Hydro	X	X	X		X					
22.	Individual	Andrew Pusztai	American Transmission Company, LLC	X									
23.	Individual	Thad Ness	American Electric Power	X		X		X	X				
24.	Individual	William Rees	Baltimore Gas and Electric Co.	X									
25.	Individual	Jason Regg	TVA	X									
26.	Individual	Michael Schiavone	Niagara Mohawk Power Corporation (dba National Grid)			X							
27.	Individual	Michael Pakeltis	CenterPoint Energy	X									
28.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
29.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
30.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									
31.	Individual	Kirit Shah	Ameren	X		X		X	X				
32.	Individual	Amy Kupferberg	Individual	NA									
33.	Individual	George Czerniewski	Consolidated Edison Company of New York, Inc. - Transmission Line Maintenance	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
34.	Individual	andres lopez	USACE					X				X	
35.	Individual	CJ Ingersoll	CECD			X							
36.	Individual	Edward J Davis	Entergy Services, Inc	X		X		X	X				
37.	Individual	David Burke	Orange and Rockland Utilities, Inc.	X		X							
38.	Individual	Saurabh Saksena	National Grid	X		X							
39.	Individual	Steve Rueckert	Western Electricity Coordinating Council										X
40.	Individual	Jody Nelson	Georgia Transmission Corp.	X									
41.	Individual	T. Wiley	Northern Indiana Public Service Company	X		X							

1. **The SDT proposes a revised NERC Glossary definition for Right-of-Way (ROW). This revised definition will be used in lieu of the Active Transmission Line ROW. Do you agree? If answer is no, please explain.**

Summary Consideration: There are 40 comments; 29 of those comments were in agreement with the definition, and 11 were in disagreement.

One repeated concern in the disagreements was whether or not "danger trees" rights outside the Right-of-Way (ROW) should be an extension of the ROW. The SDT responded "The SDT has limited the definition of Right-of-Way to a corridor of land with a defined width to operate a transmission line. This does not include danger tree rights."

Another repeated concern in the disagreements was reference to the term "blowout standard" and commenters were asking for more clarification and/or a definition of that term. To this line of comment the SDT responded "The definition includes a series of options that gives the Transmission Owner latitude in establishing ROW width. It does not require selecting a single method for its system. The term blowout standard is not capitalized and is not a defined term, and is intended to represent whatever conductor "blow out" (as opposed to vegetation "blow in") design criteria were used when the line was constructed. This phrase in the definition allows a Transmission Owner to use its internal engineering standards or the general engineering standards that were in effect when the line was constructed to determine the ROW width."

A request was made to include the definition of MVCD within the definition section of the standard. The SDT agreed with the commenter's request and used the appropriate portion of the existing language in the rationale text box associated with R1 for the MVCD definition. The SDT understands that this term will be added to the NERC glossary coincident with this standard becoming effective. This is not a substantive change to the standard, it is merely procedural.

A request was made to remove the existing and future definition of ROW from the glossary. The SDT understands that this is not consistent with the NERC intent for each repeated acronym used in multiple requirements to be available in the glossary for ready reference.

A request was made to change the definition of ROW to include special permissions given by some property owners. To this the SDT responded "The SDT has limited the definition of Right-of-Way to a corridor of land with a defined width to operate a transmission line. The SDT does not propose to change the definition because of the numerous and varied special property owner permissions that may exist, and which are not always legally binding."

A concern within one disagreement was related to possible misuse of the "pre-2007 vegetation maintenance records." The SDT explained that this term was placed in the definition as a method to cover situations where the other alternatives are not viable. The SDT will address this issue in the Technical Reference Document.

Organization	Yes or No	Question 1 Comment
SERC Vegetation Management sub-committee	No	We agree with the proposed definition as a replacement for active transmission ROW, however, in a review of NERC standards, the term ROW is not used except in FAC-003. It is therefore recommended that the term be removed from the NERC glossary. r
Response: The SDT thanks you for your comments. The SDT considered your request but cannot implement it because it is not consistent with the NERC Standards Development Process for defining the use of a term solely within a standard itself. All defined terms must be included in the glossary.		
Hydro One Networks	No	The revised definition of ROW is unclear in regards to the application of standards and/or historic records as a means of determining ROW width; is it necessary for a TO to select one method to apply in all cases, or can each span be treated in the manner deemed most appropriate by the TO? Additionally "blowout Standard" has not been defined in the document or in the technical paper, and therefore it is not clear exactly how this method would be applied, and subsequently defended under scrutiny.
Response: The SDT thanks you for your comments. The definition includes a series of options that give the Transmission Owner latitude in establishing ROW width. It does not require selecting a single method for its system. The term blowout standard is not capitalized and is not a defined term, and is intended to represent whatever conductor "blow out" (as opposed to vegetation "blow in") design criteria were used when the line was constructed. This phrase in the definition allows a Transmission Owner to use its internal engineering standards or the general engineering standards that were in effect when the line was constructed to determine the ROW width.		
Northeast Power Coordinating Council	No	There was no definition of ROW listed in FAC-003-1. The revised definition of ROW in FAC-003-2 is unclear regarding the application of standards and/or historic records as a means of determining

Organization	Yes or No	Question 1 Comment
		ROW width. Is it necessary for a TO to select one method to apply in all cases, or can each span be treated in the manner deemed most appropriate by the TO? “Blowout standard” has not been defined in the document, technical paper, or NERC Glossary and it is not clear what this method is, and exactly how it would be applied. It could not be defended under scrutiny. It is still unclear whether Danger Tree rights are included in this definition.In the NERC Glossary of Terms, Right-of-Way (ROW) is defined as “A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.” Propose keeping this definition.Is encroachment into the MVCD, or (MVCD plus additional distance as defined by the TO)? MVCD, as specified within the body of FAC-003-2 "is a calculated minimum distance stated in feet (meters) to prevent flashover between conductors and vegetation, for various altitudes and operating voltages." MVCD should be “formally” defined in this document, and the NERC Glossary. Can a list/database be established in 2011 that lists the widths for the pre-2007 vegetation management records?
Response: The SDT thanks you for your comments. The existing ROW definition in the glossary was created by and for the FAC-003-1 and was moved there when that standard was adopted. The definition includes a series of options that give the Transmission Owner latitude in establishing ROW width. It does not require selecting a single method for its system. The term blowout standard is not capitalized and is not a defined term, and is intended to represent whatever conductor “blow out” (as opposed to vegetation “blow in”) design criteria were used when the line was constructed. This phrase in the definition allows a Transmission Owner to use its internal engineering standards or the general engineering standards that were in effect when the line was constructed to determine the ROW width. The SDT has limited the definition of Right-of-Way to a corridor of land with a defined width to operate a transmission line. This does not include danger tree rights. The definition of the MVCD is now added to this Standard. While use of the pre-2007 records is a compliance issue and is not in the purview of the SDT, it is the intent of the language in the definition that you could use this information.		
Platte River Power Authority Substation Maintenance Group	No	We agree that the ROW width in no case exceeds the TO’s legal rights but may be less. We do not agree that the revised NERC Glossary definition for Right-of-Way addresses paragraph 734 of FERC Order 693 “that rights-of-way be defined to encompass the required clearance areas instead of the

Organization	Yes or No	Question 1 Comment
		corresponding legal rights, and that the standards should not require clearing the entire right-of-way when the required clearance for an existing line does not take up the entire right-of-way”. The engineering or construction standards for establishing the width of the corridor outlined in the definition are in most cases not useful. We will continue to rely on our easements and legal rights with this definition. We believe the Active Transmission Line ROW definition in the previous version more clearly addressed paragraph 734 of FERC Order 693.
Response: The SDT thanks you for your comments. The standard covers lines that have been built over many years where records could be lost. The ROW definition provides three alternatives to determine the width of the corridor to be maintained.		
NERC Staff	No	NERC supports a revised definition and prefers the definition in Draft 5 over the Active Transmission Line ROW definition used in Draft 4. NERC believes the use of the term “pre-2007 vegetation maintenance records” in the proposed definition is ambiguous and will likely be interpreted differently throughout the industry. Therefore, NERC supports this change subject to removing the aforementioned term.
Response: The SDT thanks you for your comments. The phrase “…pre-2007 vegetation maintenance records…” was placed in the definition as a method to cover situations where the other alternatives are not viable. The SDT has addressed this issue in detail in the Technical Reference Document.		
FirstEnergy	No	Although for the most part we agree with the changes to the definition of ROW, we suggest the following changes. 1. The last sentence of the definition states "The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria." We do not agree with the phrase "in no case exceeds the Transmission Owner's legal rights" because there could be instances where special permission has been granted by landowners to the TO. We suggest revising this statement to "The ROW width may be less than the Transmission Owner’s granted rights based on the aforementioned criteria."

Organization	Yes or No	Question 1 Comment
		2. Regarding the phrase "blowout standard" used in the definition, we are assuming this is in reference to the company specific calculations for sag and sway on not on any one specific industry standard. We suggest clarification such as "Transmission Owner's specific blowout or sag and sway analysis in effect when the line was built".
Response: The SDT thanks you for your comments. The SDT has limited the definition of Right-of-Way to a corridor of land with a defined width to operate a transmission line. The SDT does not propose to change the definition because of the numerous and varied special property owner permissions that may exist, and which are not always legally binding. The term blowout standard is not capitalized and is not a defined term, and is intended to represent whatever conductor “blow out” (as opposed to vegetation “blow in”) design criteria were used when the line was constructed. This phrase in the definition allows a Transmission Owner to use its internal engineering standards or the general engineering standards that were in effect when the line was constructed to determine the ROW width.		
Central Maine Power Company - IberdrolaUSA	No	The definition does not define transmission owner responsibility for areas covered by “danger tree” rights. This area is outside the maintained width but for economic and social reasons the transmission owner can not remove all danger trees. Utilities have procedures in place to remove the hazard trees but it is not practical to remove all danger trees that have the potential to violate the MVCD should they fail. This area of the definition requires clarification.
Response: The SDT thanks you for your comments. The SDT has limited the definition of Right-of-Way to a corridor of land with a defined width to operate a transmission line. This does not include danger tree rights.		
TVA	No	I suggest that "arboricultural activities or horticultural or agricultural activities be removed and changed to installation, removal or digging of vegetation.
Response: The SDT thanks you for your comments. The changes have been made in the footnotes.		
Niagara Mohawk Power Corporation (dba National	No	It is still unclear whether Danger Tree rights are included in this definition. Additional question: Can we establish a list/database in 2011 stating the widths for the pre-2007 vegetation

Organization	Yes or No	Question 1 Comment
Grid)		management records? There is no definition of ROW listed in FAC-003-1, however in the NERC Glossary of Terms, Right-of-Way (ROW) is defined as "A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines." We propose keeping this definition.
Response: The SDT thanks you for your comments. The SDT has limited the definition of Right-of-Way to a corridor of land with a defined width to operate a transmission line. This does not include danger tree rights. While use of the pre-2007 records is a compliance issue and is not in the purview of the SDT, it is the intent of the language in the definition that you could use this information.		
CenterPoint Energy	No	CenterPoint Energy agrees with the removal of "Active Transmission Line ROW" as a defined term. The change in the NERC Glossary definition for Right-of-Way (ROW) alone, however, does not address all of the remaining interpretation issues within the Standard that still exist. The following issues still require resolution: 1. The "force majeure" was moved from the Applicability section to a footnote, and is no longer an encompassing exception for each Requirement. Therefore, the "force majeure" footnote needs to be applied not only to R1, R2, R6, and R7 but also R4 and R5. For R4, notification to the control center would likely be restricted during a natural disaster. For R5, correction action by the control center may not be possible during a natural disaster. 2. The exception for applicability beyond the "Rating and all Rated Electrical Operating Conditions" should be included not only in R1, R2, and R3, but also R5 and R7. For R5 and R7, the encroachment into the MVCD should consider whether the line is operating within its design limits. 3. The use of the term "Fault" in M1 and M2 should be revised to "Sustained Outage". A "Fault" can be associated with a Momentary Outage or a Sustained Outage. The scope of R1 and R2 is specific to Sustained Outages only. The Periodic Data Submittal is specific to Sustained Outages only as well. If a later confirmation of a "Fault" by the Transmission Owner indicates that a vegetation encroachment into the MVCD was due to a fall-in from inside the ROW, yet caused only

Organization	Yes or No	Question 1 Comment
		a Momentary Outage, the Transmission Owner would be in violation of R1 because M1 considers it to be the equivalent of a Real-time observation. The current scope of the Standard is not intended to include Momentary Outages. If it was, the Periodic Data Submittal would capture this type of outage, which it does not. 4. In the Introduction Section 5 - Background, fall-ins are characterized as “statistically intermittent” and “these types of events are highly unlikely to cause large-scale grid failures”. CenterPoint Energy agrees and therefore recommends that fall-ins be excluded from the Requirements R1, R2, and Periodic Data Submittal of outages. This would negate the need for determining the limits of the ROW, thus simplifying the Standard to a great margin while not sacrificing the emphasis of the Standard. The Draft 5 Background Information states the criteria for developing a results-based reliability standard such that “each requirement should identify a clear and measurable expected outcome.” When the determination of the limits of the ROW goes beyond the interpretation of the legal limits of the ROW, it adds a level of complexity that may be unclear and not deterministically measurable. 5. For R6, CenterPoint Energy believes the detailed rationale and studies used for the determination of the required one year inspection cycle should be included in the Guidelines and Technical Basis. The explanation provided in the Rationale that it is “based upon average growth rates across North America and on common utility practice” are unfounded and arbitrary without a specific reference to a North American study. 6. R7 contains the phrase, “provided they do not put the transmission system at risk of a vegetation encroachment”. CenterPoint Energy recommends this phrase be replaced with the more specific terminology used in the Rationale for R7 and R3: “provided they do not allow encroachment of vegetation into the MVCD.” 7. CenterPoint Energy believes the Periodic Data Submittal should be clarified as to the specific conditions under which Sustained Outages are reported. There is a reference to footnote 2 regarding the exclusion for the “force majeure”; however, the exclusion for lines operating outside their design limits as mentioned in R1, R2, and R3 is missing. CenterPoint Energy believes the

Organization	Yes or No	Question 1 Comment
		wording should be changed to include all applicable exclusions for added clarity and recommends the following wording: "The Transmission Owner will submit a quarterly report to its Regional Entity, or Regional Entity's designee, identifying all Sustained Outages of applicable transmission lines operating within their Facility Rating and all Rated Electrical Operating Conditions as determined by the Transmission Owner to have been caused by vegetation, except as excluded in footnote 2, which includes as a minimum, the following:" 8. The Guidelines and Technical Basis and the Technical Reference with the Gallet Equation should be combined into one document as a supplement to the Standard to avoid duplication in wording and misinterpretation of context. 9. The Guideline and Technical Basis under Requirement R6 refers to the "percentage of the required ROW inspections completed" and should be revised to match the wording of R6 and the VSL for R6 as the "percentage of applicable transmission line inspections completed." 10. CenterPoint Energy agrees that the Rationale test boxes should be deleted from the Standard and applicable explanatory text be included within the Guidelines and Technical Basis. 11. The Guidelines and Technical Basis should contain specific examples for determining if a fall-in is considered inside or outside the ROW. 12. CenterPoint Energy recommends modifying the Technical Reference section regarding "Selecting a Maintenance Approach" to delete the sentences beginning with, "If constraints cannot be overcome and if design clearances are sufficient..." and continuing through to, "identified early for rectification." This example may lead the public to inappropriately ask the utilities for exceptions to allow vegetation beneath the transmission lines, and it also does not address the dynamics of future modifications to the transmission lines (e.g. higher operating temperatures or new conductors) that may necessitate reduced clearances to ground, thus requiring removal of now mature vegetation. The example should not be included in a Standard intended to reduce vegetation risks to the transmission system. It is also in conflict with later statements in the Technical Reference regarding Set Objectives which emphasize maintaining access and clear lines of

Organization	Yes or No	Question 1 Comment
		sight. 13. In general, CenterPoint Energy strongly believes the proposed FAC-003-2 has gone far beyond what was contemplated by the Commission in FERC Order 693. The Commission's determination dealt with the following areas: (1) applicability; (2) inspection cycles; and (3) minimum clearances on National Forest Service lands. For instance, in Paragraph 729, the Commission states, “As proposed in the NOPR, the Commission approves Reliability Standard FAC-003-1 with no proposed modification on the issue of clearances. The Commission reaffirms its interpretation that FAC-003-1 requires sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions....” Rewriting the minimum clearances introduces a new set of confusing definitions, and further burdens the Transmission Owners with new documentation requirements while providing little, if any, benefit when compared to the Clearance 2 concept in the existing Standard.A preferred approach would be to incorporate the following few items into the existing Standard FAC-003-1: (1) the RC versus the RRO; (2) the designation of a specific inspection frequency; (3) the Gallet equation; and (4) the applicability to National Forest Service lands.
Response: The SDT thanks you for your comments: For clarity the SDT separated various items in your comments and repeated them below with the numbered responses: CenterPoint Energy agrees with the removal of “Active Transmission Line ROW” as a defined term. The change in the NERC Glossary definition for Right-of-Way (ROW) alone, however, does not address all of the remaining interpretation issues within the Standard that still exist. The following issues still require resolution: 1. The “force majeure” was moved from the Applicability section to a footnote, and is no longer an encompassing exception for each Requirement. Therefore, the “force majeure” footnote needs to be applied not only to R1, R2, R6, and R7 but also R4 and R5. For R4, notification to the control center would likely be restricted during a natural disaster. For R5, correction action by the control center may not be possible during a natural disaster. **Response:** Thank you for your comment. The SDT considers the term “without intentional delay” to be adequate coverage for force majeure issues in R4. R5 requires that if you cannot perform work regardless of the reason you must come up with a plan to ensure that you prevent		

Organization	Yes or No	Question 1 Comment

encroachments, therefore a force majeure exemption is not applicable.

2. The exception for applicability beyond the “Rating and all Rated Electrical Operating Conditions” should be included not only in R1, R2, and R3, but also R5 and R7. For R5 and R7, the encroachment into the MVCD should consider whether the line is operating within its design limits.

Response: The SDT thanks you for your comments. The SDT made the suggested changes to remove references to arboricultural, horticultural or agricultural activities from the footnote 2, but did not adopt the suggestion for the new footnote 6 which replaces the footnote 4 to which you refer” because that footnote 4 is concerned with completing the annual work plan, The SDT does not envision that actions by property owners such as installation, or removal or digging of vegetation as a valid impediment to completion of the annual work plan. However this term is relevant in R1 and R2 and as such is within foot note 2 because such actions do occur from time to time without the transmission Owner’s knowledge and do then result in conditions that could lead to encroachments and outages before the Transmission Owner has the opportunity to rectify the condition.

3. The use of the term “Fault” in M1 and M2 should be revised to “Sustained Outage”. A “Fault” can be associated with a Momentary Outage or a Sustained Outage. The scope of R1 and R2 is specific to Sustained Outages only. The Periodic Data Submittal is specific to Sustained Outages only as well. If a later confirmation of a “Fault” by the Transmission Owner indicates that a vegetation encroachment into the MVCD was due to a fall-in from inside the ROW, yet caused only a Momentary Outage, the Transmission Owner would be in violation of R1 because M1 considers it to be the equivalent of a Real-time observation. The current scope of the Standard is not intended to include Momentary Outages. If it was, the Periodic Data Submittal would capture this type of outage, which it does not.

Response: Thank you for your comment. The reporting of Sustained Outages is simply to fulfill routine data submission. The SDT does not intend to create a system that requires a root cause analysis of all Faults which are not Sustained Outages. The SDT did intend for those Faults as referenced in M1 and M2 to be considered the equivalent of an encroachment observed in real time. The SDT also notes that the term Fault is an existing defined term and momentary interruption is not.

4. In the Introduction Section 5 - Background, fall-ins are characterized as “statistically intermittent” and “these types of events are highly unlikely to cause large-scale grid failures”. CenterPoint Energy agrees and therefore recommends that fall-ins be excluded from the Requirements R1, R2, and Periodic Data Submittal of outages. This would negate the need for determining the limits of the ROW, thus simplifying the Standard to a great margin while not sacrificing the emphasis of the Standard. The Draft 5 Background Information states the criteria for developing a results-based reliability standard such that “each requirement should identify a clear and measurable expected outcome.” When the determination of the limits

Organization	Yes or No	Question 1 Comment
of the ROW goes beyond the interpretation of the legal limits of the ROW, it adds a level of complexity that may be unclear and not deterministically measurable. **Response:** Thank you for your comment. Fall-ins from inside the ROW are indicators of a poor performing vegetation management program. The definition of Right-of-Way identifies methods to define the width of the corridor establishing whether vegetation was located within the ROW and subject to the Transmission Owner's legal rights. 5. For R6, CenterPoint Energy believes the detailed rationale and studies used for the determination of the required one year inspection cycle should be included in the Guidelines and Technical Basis. The explanation provided in the Rationale that it is "based upon average growth rates across North America and on common utility practice" are unfounded and arbitrary without a specific reference to a North American study. **Response:** Thank you for your comment. The SDT established an inspection cycle at least once per calendar year and with no more than 18 months between inspections on the same ROW. This cycle was based on industry comments submitted to Draft 1 of this standard ending on 11-25-2008 6. R7 contains the phrase, "provided they do not put the transmission system at risk of a vegetation encroachment". CenterPoint Energy recommends this phrase be replaced with the more specific terminology used in the Rationale for R7 and R3: "provided they do not allow encroachment of vegetation into the MVCD." **Response:** Thank you for your comment. The SDT agrees and has made the requested change to the draft standard. 7. CenterPoint Energy believes the Periodic Data Submittal should be clarified as to the specific conditions under which Sustained Outages are reported. There is a reference to footnote 2 regarding the exclusion for the "force majeure"; however, the exclusion for lines operating outside their design limits as mentioned in R1, R2, and R3 is missing. CenterPoint Energy believes the wording should be changed to include all applicable exclusions for added clarity and recommends the following wording: "The Transmission Owner will submit a quarterly report to its Regional Entity, or Regional Entity's designee, identifying all Sustained Outages of applicable transmission lines operating within their Facility Rating and all Rated Electrical Operating Conditions as determined by the Transmission Owner to have been caused by vegetation, except as excluded in footnote 2, which includes as a minimum, the following:" **Response:** Thank you for your comment. The SDT added your recommended language on "within its Rating and all Rated Electrical Operating		

Organization	Yes or No	Question 1 Comment

Conditions”.

8. The Guidelines and Technical Basis and the Technical Reference with the Gallet Equation should be combined into one document as a supplement to the Standard to avoid duplication in wording and misinterpretation of context.

Response: Thank you for your comment. The Guideline and Technical section is part of the NERC Results Based Standard format. The Technical Reference is a supplemental document that explains the VMSDT thought process in developing the requirements and applies to this version of the standard.

9. The Guideline and Technical Basis under Requirement R6 refers to the “percentage of the required ROW inspections completed” and should be revised to match the wording of R6 and the VSL for R6 as the “percentage of applicable transmission line inspections completed.”

Response: Thank you for your comment. VSL’s for R6 has been changed to align with the NERC Standard Development guidelines to “a Transmission Owner failed to inspect”.

10. CenterPoint Energy agrees that the Rationale test boxes should be deleted from the Standard and applicable explanatory text be included within the Guidelines and Technical Basis.

Response: Thank you for your comment.

11. The Guidelines and Technical Basis should contain specific examples for determining if a fall-in is considered inside or outside the ROW.

Response: Thank you for your comment. The SDT established the definition of a ROW and a fall-in resulting from vegetation would be determined through investigation of the sustained outage.

12. CenterPoint Energy recommends modifying the Technical Reference section regarding “Selecting a Maintenance Approach” to delete the sentences beginning with, “If constraints cannot be overcome and if design clearances are sufficient...” and continuing through to, “identified early for rectification.” This example may lead the public to inappropriately ask the utilities for exceptions to allow vegetation beneath the transmission lines, and it also does not address the dynamics of future modifications to the transmission lines (e.g. higher operating temperatures or new conductors) that may necessitate reduced clearances to ground, thus requiring removal of now mature vegetation. The example should not be

Organization	Yes or No	Question 1 Comment
included in a Standard intended to reduce vegetation risks to the transmission system. It is also in conflict with later statements in the Technical Reference regarding Set Objectives which emphasize maintaining access and clear lines of sight. **Response:** Thank you for your comment. This verbiage is part of an example describing a combination of strategies which may be utilized by a Transmission Owner. 13. In general, CenterPoint Energy strongly believes the proposed FAC-003-2 has gone far beyond what was contemplated by the Commission in FERC Order 693. The Commission's determination dealt with the following areas: (1) applicability; (2) inspection cycles; and (3) minimum clearances on National Forest Service lands. For instance, in Paragraph 729, the Commission states, "As proposed in the NOPR, the Commission approves Reliability Standard FAC-003-1 with no proposed modification on the issue of clearances. The Commission reaffirms its interpretation that FAC-003-1 requires sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions...." Rewriting the minimum clearances introduces a new set of confusing definitions, and further burdens the Transmission Owners with new documentation requirements while providing little, if any, benefit when compared to the Clearance 2 concept in the existing Standard.A preferred approach would be to incorporate the following few items into the existing Standard FAC-003-1: (1) the RC versus the RRO; (2) the designation of a specific inspection frequency; (3) the Gallet equation; and (4) the applicability to National Forest Service lands. **Response:** Thank you for your comment. The SDT believes the FAC 003-2 is an improvement over Version 1 and followed the SAR establishing that the SDT should revise the standard.		
Duke Energy	Yes	
South Carolina Electric and Gas	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	

Organization	Yes or No	Question 1 Comment
Individual		My Comments do not relate to the question asked, however, I saw no other place to add my comment. I would like to thank NERC for allowing the public to participate in the process of improving the reliability standard FAC-003-1. I became interested in Vegetation Management requirements for Transmission Lines, after Con Edison clear cut the ROW behind my home. I appreciate the importance of safe and reliable electrical service, and recognize how an effective TVMP contributes to this goal. In this whole process, what has dispirited me the most, is the inaccurate information being conveyed about why the clear cutting was necessary and, the causes of the August 14th, 2003 blackout. The narrative goes something like..”a tree falling onto transmission lines caused the black out of 2003.” I find it harmful because it misdirects the focus from the grid’s short fallings, and impedes upgrading the system to improve reliability. I found this same philosophy in the initial pages of CN Utility’s document, UTILITY VEGETATION MANAGEMENT FINAL REPORT MARCH 2004. It suggests that had the trees been adequately maintained, the blackout would have most “likely” not happened. Now I am aware of the qualification of the word “likely,” but the document is heavily weighted on the contribution of tree contact to the blackout. We know that de-regulation and the physical nature of A.C. current had more to do with the causes of the blackout, than tree contact. The timeline shows a range of cascading system failures that created the catastrophic event. The trouble began at 1:58 p.m. when First Energy generating plant in Eastlake, Ohio, shuts down. At 3:06 p.m. a First Energy 345-kV transmission line fails. As a result, at 3:17 p.m voltage dips temporarily on the Ohio portion of the grid. Controllers take no action, but power shifted onto another power line, overloading it and, causing it to sag into a tree and go offline at 3:32 p.m. Mid West ISO and First Energy controllers fail to inform system controllers in nearby states. At 3:41 and 3:46 p.m., two breakers connecting First EnergyÊ¼s grid with American Electric Power are tripped. 4:05 p.m., a sustained power surge on some Ohio lines signals more trouble building. At 4:09:02 p.m., voltage sags deeply, as Ohio draws 2 GW of power from Michigan. 4:10:34 p.m., many transmission lines trip out, beginning in

Organization	Yes or No	Question 1 Comment
		Michigan and then in Ohio, blocking the eastward ï¬‚ow of power. Generators go down, creating a huge power deficit, in seconds, power surges out of the East, tripping East coast generators, and the rest is history. The U.S.-Canada Power System Outage Task Force: Final Report on Implementation of Recommendations, September 2006, states that “Inadequate reactive supply was a factor in most of the events.” and “the assumed contribution of dynamic reactive output of system generators was greater than the generators actually produced, resulting in more significant voltage problems.” The backup generators were not adequate to handle the amperage load or voltage needed. A lack of coordination of System Protection Programs(relays tripping), inadequate communication between Utilities/TOs, and lack of "training of operating personnel in dealing with severe system disturbances" are all the causes for the blackout. With respect to vegetation management, the findings from The U.S.-Canada Power System Outage Task Force: Final Report on Implementation of Recommendations, September 2006, clearly did not intend for transmission owners to develop a one-size-fits-all standard. The Energy Policy Act of 2005, initiated NERC to draft and adopt the standard FAC-003-1. When I read through the standard, it all seems very reasonable. I can understand the stiff penalties for noncompliance because it seems, like an easy fix, compared to the necessary, major changes in infrastructure. The principles further outlined in ANSI A300 VII, and “Best Practices” IVM, seem very reasonable too. There is mention of the environment, property owners, even proper pruning techniques. The wire zone clearance of 10 feet and, allowing low growing compatible vegetation in the boarder zone, seems to retain more vegetation, than remove. However, in practice, the TOs are simply clear cutting the ROW, with no regard for the enviroment, the trees that they are cutting, or the abutting properties. It took Con Edison 2 1/2 half days to clear 450 tress form behind our home. We are now forced to see and hear 93,000 cars a day from the Sprain Parkway. Following the clearing, our real estate broker dropped the asking price by 30%. The house remains empty and unsold. Apparently, no one is interested in spending 32,000K a year in property taxes to look at transmission towers/lines and live on a highway. This has been

Organization	Yes or No	Question 1 Comment
		devastating to our family, and thousands of others in Westchester County. They removed a buffer of trees that were 150 feet away from wires and towers, on a downward slope. These trees would have never made contact with conductors. Con Edison's defense is that they did it because it was in their right to. Moreover, they use the NERC fine structure to defend their behavior.I went through the Notice of Penalties that NERC has issued from 6/2/08-2/01/11. Out of 646 Notice of Penalties, 1700 violations were sited, 36 out of 1700 penalties were issued for violations to the FAC- 003-1 standard. Some NOPs had multiple violations-18 R1 violations were cited and 29 penalties were issued for R2 violations. Out of the 29 R2 penalties, 20 involved tree contact. Some outages were caused by sagging wires, some were caused by arcing electricity looking for a ground fault, but none were caused by a tree falling onto the transmissions wires. The numbers should put into perspective how immaterial the problem of tree contact really is. Think about it... 20 out of 1700 involved tree contact, and none of then resulted in a sustained outage. That means 1680 violations were issued due to other system failures. To use these penalties as an excuse is a complete over exaggeration. What is missing from the standard and the fine structure, are penalties for over cutting and violations to other stipulations, such as proper communication, training, and aftercare of the affected areas. The problems that have arisen from current TVMP activities being executed nationally on our ROWs, is not a public perception problem. Rather, TOs are not complying with standards that are meant protect the environment and they are not respecting the property rights of the neighboring homeowners. I appreciate the opportunity to share my views, and would take any opportunity to further participate in protecting the rights of property owners, and the environment, while working to secure safe and reliable electrical service. Most respectfully, Amy M Kupferberg - Utility Whisperer

Response: The SDT thanks you for your comments. You raise a host of issues regarding the operations of electric transmission systems as well as recounting the blackout of 2003. We agree there seems to be wide public opinion of what actually was the cause of the blackout. Relative to your recommendations for our team, we note that appropriate NERC standards contain requirements regarding training and communications among

Organization	Yes or No	Question 1 Comment
other things. For example, requirement R4 of this standard contains language which requires communication when certain vegetation conditions are discovered. As you know training and communications were just two of the many issues addressed in the blackout report. In response to your comment "What is missing from the standard and the fine structure, are penalties for over cutting and violations to other stipulations, such as proper communication, training, and aftercare of the affected areas," this Standard is meant to define what needs to be accomplished to achieve reliability; it is up to the Transmission Owner to perform the vegetation maintenance in a manner to accomplish that goal consistent with applicable environmental concerns and local regulations.		
Consolidated Edison Company of New York, Inc. - Transmission Line Maintenance	Yes	
USACE	Yes	
CECD	Yes	
Entergy Services, Inc	Yes	The revised Glossary definition of ROW helps to clarify the intent of what is expected and/or considered ROW stipulations. This is a beneficial addition/clarification.
Response: The SDT thanks you for your comments.		
Orange and Rockland Utilities, Inc.	Yes	
National Grid	No	The revised ROW definition emphasizes the ROW width needed to operate the transmission line(s). It is National Grid's interpretation that the width established when the line was constructed is the width to be maintained. This width is documented in engineering drawings, per-2007 vegetation records or blow-out standards. This definition does not imply that danger tree rights beyond the constructed and maintained width are incorporated in the definition; therefore fallins - from

Organization	Yes or No	Question 1 Comment
		outside the ROW but within within an area with danger tree rights would not be considered fallin-ins from within the ROW. National Grid would like the SDT to comment on this interpretation in its response to these comments.
Response: The SDT thanks you for your comments. Your interpretation is consistent with the intent of the definition that the SDT provided. However the definition includes a series of options that give the Transmission Owner latitude in establishing ROW width. It does not require selecting a single method for its system. This phrase in the definition allows a TO to use its internal engineering standards or the general engineering standards that were in effect when the line was constructed to determine the ROW width. The SDT has limited the definition of Right-of-Way to a corridor of land with a defined width to operate a transmission line. This does not include danger tree rights.		
Western Electricity Coordinating Council	Yes	
Georgia Transmission Corp.	Yes	
Northern Indiana Public Service Company	Yes	

2. **In R1 and R2 and their associated VSLs, the SDT added the phrase "in order of increasing severity" and added the sentence "The types of encroachments are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO's vegetation maintenance program." to the Rationale boxes for R1/R2. Do you agree? If answer is no, please explain.**

Summary Consideration: 32 of the 38 responses agreed with the changes. The SDT made changes to the footnotes in response to 4 requests. Three of the "yes" response comments included positive references to the improved clarity, alignment with results based standards, reinstatement of Category 3 outages and the importance of investigations which will be necessary to categorize violations across the various VSLs.

The disagreements included concerns over the relationships between the VSLs and language in requirements. The SDT revised the language in the Rationale box to explain the program performance relationships between types of encroachments, faults and outages, and various types of failed maintenance, and how the various types of failed maintenance have historically been associated with known vegetation related events.

In response to a request to exchange the order of severity levels of the failure to maintain vegetation to prevent encroachments from blowing together versus fall-ins, the SDT explained that the blowing together is considered a higher severity level of failed maintenance since the sway of the conductor is in most cases more determinable and less variable than the more complex geometry associated and numerous variables associated with fall-ins.

In response to a comment that there was no need for R1 and R2, the SDT explained that removal of R1 and R2 could be viewed as lessening the reliability of the standard.

One comment recommended that the standard include language to allow any encroachment found and removed, absent a Fault or Sustained Outage, to not be considered a violation. The SDT noted that the MVCD is a component that must be considered in the "building block" approach inherent in the standard, and as such, any encroachment inside the MVCD indicates a significant failure in overall vegetation program approach.

One comment requested a return to the Clearance 1 in the existing standard to support work that is resisted by property owners and other parties that do not want vegetation to be adequately maintained. The SDT referenced the problem associated with a fill-in-the-blank requirement, and explained how this standard does not preclude a utility from removing or pruning vegetation well beyond the MVCD, but primarily focuses on determining when a violation occurs. The SDT asserts that vegetation maintenance must address the many variables that exist such as growth rates, vegetation maintenance cycles, conductor sag and sway, etc. that could result in an encroachment of the MVCD which would be a direct violation of the standard. The vegetation program must factor in delays and/or mitigation measures associated with stakeholder concerns, but must clearly communicate the need for maintenance to ensure strict compliance with this zero-tolerance standard.

Organization	Yes or No	Question 2 Comment
SERC Vegetation Management sub-committee	Yes	
Hydro One Networks	Yes	
Northeast Power Coordinating Council	Yes	
Platte River Power Authority Substation Maintenance Group	Yes	
Bonneville Power Administration	Yes	BPA prefers the stratified levels of violation severity presented in the table for R1 and R2.Foot note #2 on page 8 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. What specifically does this phrase refer to?Foot note #4 on page 12 needs to be clarified with respect to arboricultural activities or horticultural or agricultural activities. What specifically does this phrase refer to?

Response: The SDT thanks you for your comments.

The SDT has changed footnote 2 to read as follows:

This requirement does not apply to circumstances that are beyond the control of a Transmission Owner subject to this reliability standard,

Organization	Yes or No	Question 2 Comment
including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW. The SDT has changed footnote 4 (now footnote 6 in the revised standard) to read as follows: Circumstances that are beyond the control of a Transmission Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or an applicable regulatory body.		
NERC Staff	No	The sentence was added to the rationale but the phrase "in order of increasing severity" is not in the requirement or their associated VSLs. NERC staff does not support the language in the rationale box which differentiates the VSL based on skill level of maintenance personnel rather than the impact to reliability of the encroachment. The VSL should be based on whether or not the owner managed the vegetation to prevent encroachment and therefore be binary. See additional comments submitted separately regarding combining R1 and R2.
Response: The SDT thanks you for your comments. VSLs should not be assigned based on the impact to reliability, as is proposed by the commenter. NERC's VSL Guidelines state the following regarding VSLs: "This is not the same as saying that the requirement is really important and any noncompliance would have an adverse reliability impact – **the impact to reliability should be addressed through the VRF, not the VSL."** However, the SDT has made changes to reword the rationale in R1 and R2 to further explain how program performance must successfully account for the relationships between types of encroachments, faults and outages, various types of failed maintenance, and how the various types of failed maintenance have historically been associated with known vegetation related events.		
Pepco Holdings Inc and Affiliates	Yes	
FirstEnergy	No	For the Requirement R1 and R2 VSLs, we suggest that the proposed Moderate (fall-ins) and High (blowing together) VSL be interchanged. We believe that fall-ins are more severe encroachments than blowing together and the categories listed in the compliance section support this point.

Organization	Yes or No	Question 2 Comment
		Category 1 (grow-ins) is most severe, followed by Category 2 & 3 (fall-ins) and Category 4 (blowing together).
Response: The SDT thanks you for your comments. The choice of the VSL for the fall-ins versus the blowing together was made by the SDT using logic in the language in the rationale text box for R1: "The types of failure to manage vegetation are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO's vegetation maintenance program, since the encroachments listed require different and increasing levels of skills and knowledge and thus constitute a logical progression of how well, or poorly, a TO manages vegetation relative to this Requirement."		
Dominion Electric Market Policy	Yes	
Southern Company Transmission	Yes	
Arizona Public Service Company	No	This is a reliability standard and the TO should know what its clearance needs are at all rated conditions, especially considering today's technology. If the TO manages to this standard there is no need for R1 and R2.
Response: The SDT thanks you for your comments. Elimination of R1 and R2 would be considered as a lessening of the standard.		
Salt River Project	Yes	
Tampa Electric Company	Yes	Adds clarity to the VSL from an audit perspective, this is an improved description to the Standard.
Response: The SDT thanks you for your comments.		
NextEra Energy	Yes	Although NextEra Energy Inc. (NextEra), including Florida Power & Light Company, agrees with the changes referenced for R1 and R2, NextEra is concerned that the exemptions identified in footnote

Organization	Yes or No	Question 2 Comment
		2 for "...arboricultural activities or horticultural or agricultural activities...," and similar language in footnote 4, are too broad. For example, this language appears to include an exemption for a landowner, who, during arboricultural activities or horticultural or agricultural activities, causes a vegetation contact with a transmission line (e.g., cutting or lifting a tree into a transmission line). This places the Transmission Owner in the difficult position of a landowner arguing it is exempt from a controllable risk. Thus, the "...arboricultural activities or horticultural or agricultural activities..." references should be removed from footnote 2, and the similar language in footnote 4
Response: The SDT thanks you for your comments. The SDT made the suggested changes.		
SDG&E	Yes	
ASSET MANAGEMENET	Yes	
Hydro-Quebec TransEnergie (NCR07112)	Yes	
Kansas City Power & Light	No	These proposed Requirements, Measures and Violation Severity Levels as written do not give credit to the Transmission Owners for effectively monitoring their systems and taking appropriate actions in regard to vegetation clearing. Why does it make sense to punish and penalize a Transmission Owner for discovering an encroachment when they take the appropriate actions to remedy the condition before any facility outage occurs that results in compromising the reliability of the Bulk Electric System? These Requirements, Measures and VSL's should recognize the good practices of effective response to a vegetation condition and penalize ineffective response. Recommend the SDT consider including appropriate language to recognize effective remedial actions by Transmission Owners and by doing so, recognize effective efforts instead of punishing them. In addition, proving encroachments have not occurred will pose audit challenges in determining that encroachments have not occurred for the Auditors as well as Registered Entities. If no encroachments occur, then there is nothing to report or record. This is a weak platform to stand

Organization	Yes or No	Question 2 Comment
		compliance on. Facility interruption events caused by vegetation contacts is definitively measurable and recordable. Recommend the SDT reconsider the concept of compliance with FAC-003 on the basis of sustained outages and remove the references regarding encroachments only. Recommend the SDT remove the LOWER VSL language from Requirements R1 and R2 and revise the Requirements and Measures to reflect the same.
Response: The SDT thanks you for your comments. The MVCD was established as a beginning of a series of "building blocks" for a good program. R3 requires that a TO add to MVCD distances with further considerations for the variables of conductor movement and the variables associated with vegetation growth when designing the TO's overall vegetation management approach(s). The net result of this "building block" approach is the management of vegetation at clearance distances much greater than the MVCD distances. Other related requirements of this "Defense in Depth" Standard serve to address any number of scenarios which may arise or hinder the TO's ability to always strictly adhere to the management approach(s) established within R3. Thus the other requirements of this Standard provide the latitude for "appropriate actions to remedy the condition" without penalty. Further, it is obvious that trees which have encroached inside of the MVCD are clear evidence of a failed vegetation management program.		
Manitoba Hydro	Yes	
Central Maine Power Company - IberdrolaUSA	Yes	
BC Hydro	Yes	
American Transmission Company, LLC	Yes	
American Electric Power	No	American Electric Power believes that the phrase "arboricultural activities or horticultural or agricultural activities" was mistakenly introduced into Footnotes 2 and 4, and should be deleted from both footnotes. If the phrase remains in the Standard, it may empower orchard growers, landowners and others to plant trees on the right of way and challenge Transmission Owners'

Organization	Yes or No	Question 2 Comment
		rights to perform maintenance on the presumption that the standard will exempt the TO from violating the outage or encroachment requirements.
Response: The SDT thanks you for your comments. The SDT made the suggested changes.		
Baltimore Gas and Electric Co.	Yes	
TVA	Yes	
Niagara Mohawk Power Corporation (dba National Grid)	Yes	
CenterPoint Energy	Yes	
Duke Energy	Yes	We agree with the drafting team's approach, and also agree with reinstating reporting of Category 3 (Fall-ins from outside the ROW) in the Additional Compliance Information section. The SDT responded to comments submitted with the last ballot that:"Zero tolerance for vegetation caused outages is a stated goal of FERC and NERC as it relates to this standard. This policy is part of FAC-003-1 and in concept did not change with the proposed version. The SDT recognizes this concern and has developed gradation taking into account line criticality in VRF's and type of outage not contained in the current version FAC-003-1. Finally, it is also important to note that each and every incident or potential violation is investigated and addressed based on the specific circumstances surrounding the particular event. These investigations should necessarily take into consideration and recognize the utility's individual efforts in responding to an encroachment situation." In addition, we believe that clarifying changes need to be made to footnotes 2 and 4. Clarify footnote 2 by removing the phrase "arboricultural activities or horticultural or agricultural activities" and replacing it with the phrase "installation of". Similarly, clarify footnote 4 by removing the phrase "arboricultural, horticultural or agricultural activities", and replacing it with the phrase "or human

Organization	Yes or No	Question 2 Comment
		activities such as installation, or removal or digging of vegetation.”
Response: The SDT thanks you for your comments. The SDT made the suggested changes to remove references to arboricultural, horticultural or agricultural activities from the footnote 2, but did not adopt the suggestion for the new footnote 6 which replaces the footnote 4 to which you refer” because that footnote 4 is concerned with completing the annual work plan, The SDT does not envision that actions by property owners such as installation, or removal or digging of vegetation as a valid impediment to completion of the annual work plan. However this term is relevant in R1 and R2 and as such is within foot note 2 because such actions do occur from time to time without the transmission Owner’s knowledge and do then result in conditions that could lead to encroachments and outages before the Transmission Owner has the opportunity to rectify the condition.		
South Carolina Electric and Gas	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	This is more in alignment with a results-based reliability standard.
Response: The SDT thanks you for your comments.		
Individual		
Consolidated Edison Company of New York, Inc. - Transmission Line Maintenance	Yes	
USACE	Yes	

Organization	Yes or No	Question 2 Comment
CECD	Yes	
Entergy Services, Inc	Yes	
Orange and Rockland Utilities, Inc.	Yes	
National Grid	Yes	
Western Electricity Coordinating Council	Yes	
Georgia Transmission Corp.	Yes	
Northern Indiana Public Service Company	No	While there are some enhancements to the organization and content of the standard such as the addition of the Guidelines and Technical Basis section, clarification of what constitutes evidence of compliance, and tailoring of VSL severity levels for the requirements based on the risk each poses to the likelihood of contributing to a cascade, too many elements present in FAC-003-1 and which are vital to preventing vegetation caused outages and maximizing system reliability, have been eliminated from FAC-003-2. Specifically, the elimination of concrete, declared and audited clearance standards between vegetation and conductors (the existing Clearance 1 and Clearance 2 (R1.2)) Requirements) in the revised standard is a major defect that will decrease system reliability. It has been indispensable for NIPSCO when communicating with stake holders (governments, interest groups, land owners, the public, etc.) to point to these clearance standards to give credibility and support to the kind of tree removal and trimming that is necessary to achieve the stated objective of zero preventable tree caused outages. Without these declared clearance standards in the NERC standard, utility vegetation managers will constantly be challenged by stake holders to show them that such work is required rather than an elective choice on the utility's part. One of the key lessons learned from the 2003 blackout and First Energy's overgrown ROW tree

Organization	Yes or No	Question 2 Comment
		problem was that individual land owners, local governments, and interest groups will exert pressure on the utility to only do the minimum amount of vegetation management. Without external and enforceable Vegetation Clearance Standards and by returning to a pre-2003 regime where the extent of vegetation clearing is left to the individual discretion and pressures at each utility, there is no doubt that tree clearance conditions will deteriorate over time and put system reliability at greater risk of vegetation contact.
Response: The SDT thanks you for your comments. At the request of FERC in Order 693, the SDT was asked to eliminate the fill-in-the-blank clearance requirements that are currently in FAC-003-1. A proven Engineering calculation was utilized to determine when a transmission line could spark over to vegetation without direct contact. Based on this calculation, each utility must determine what clearance levels need to be maintained as part of their TVMP. The current version does not preclude a utility from removing or pruning vegetation well beyond the MVCD, it just establishes a line in the sand that determines when a violation occurs. Individual TOs must establish a program that addresses the many variables that exist such as growth rates, vegetation management cycles, conductor sag and sway, etc. that could result in an encroachment of the MVCD which would be a direct violation of the standard. Establishing a specific clearance value to be attained during vegetation management activities is too prescriptive and is in direct conflict with the Results-Based Standard initiative that the SDT is currently implementing. Each TO must factor in delays and/or mitigation measures associated with stakeholder concerns but must clearly communicate the challenges with maintaining strict compliance with this zero-tolerance standard.		

3. **In response to comments received regarding the term “investigation” in M1/M2, the SDT substituted “confirmation…by the Transmission Owner..” in its place, among other minor edits to these measures. Do you agree? If answer is no, please explain.**

Summary Consideration: 34 of the 40 comments agreed with the change. One of the affirmative comments noted the need to make a minor change in the Guidelines and Technical Basis to assure conformance with the standard language; that change was made.

One commenter questioned what would compel an entity to document and report outages. The SDT feels that this issue is addressed by the NERC Sanctions guidelines.

It was noted that the last two paragraphs in M1 and M2 were not really measures and should be addressed in the requirements. The requirements now include this language in footnote 3.

Two commenters wished to include language to exempt brief encroachments into the MVCD due to falling trees. The SDT chose not to make that change due to concerns raised by regulatory observers.

One commenter felt that a violation should occur for any calculated potential for an MVCD encroachment. The SDT noted that the MVCD is a beginning of a series of “building blocks” for a program to ensure reliability within the line’s rating and all rated electrical operating conditions. R3 requires that a TO add to MVCD distances with further considerations for the variables of conductor movement and the variables associated with vegetation growth when designing the TO’s overall vegetation management approach(s). Additionally there is a “Defense in Depth” in this Standard to address any number of scenarios which may arise or hinder the TO’s ability to always strictly adhere to the management approach(s) established within R3. Thus the other requirements of this Standard provide the latitude for appropriate actions to remedy the condition without penalty.

One comment replied that there was no value to the measure due to the lack of reference to a violation for any calculated potential MVCD encroachment. The SDT pointed again to requirement R3 which requires this to be addressed in the maintenance strategies in R3.

One commenter suggested to delete the reference to measures in the evidence retention section; the SDT chose to retain the existing language.

Organization	Yes or No	Question 3 Comment

Organization	Yes or No	Question 3 Comment
SERC Vegetation Management sub-committee	Yes	
Hydro One Networks	Yes	
Northeast Power Coordinating Council	Yes	
Platte River Power Authority Substation Maintenance Group	Yes	
Bonneville Power Administration	Yes	
NERC Staff	No	Concur with restating as mentioned above. Other issues remain regarding data reports indicating no sustained outages or real-time observations. These measures appear to indicate that if the outages or real-time observations are not documented then an encroachment didn't occur. What will compel an entity to document these occurrences? In addition, the last two paragraphs of the Measure are not really measures. They would be better served as part of the Requirement.
Response: The SDT thanks you for your comments. The issue of how does one prove that an event did not occur is problematic. A TO must document the inspections it completes. If an inspection does not note an encroachment then none was observed. The NERC Sanction Guidelines provide adequate sanctions for the dishonest. The SDT agrees that the last two paragraphs are not measures and would belong in the requirement. The SDT has moved them to the requirement as footnotes.		
Pepco Holdings Inc and Affiliates	Yes	

Organization	Yes or No	Question 3 Comment
FirstEnergy	Yes	
Dominion Electric Market Policy	Yes	
Southern Company Transmission	No	We would recommend the middle paragraph of M1 and M2 be revised as follows: "If a later confirmation of a Fault by the TO shows that vegetation encroachment within the MVCD has occurred from vegetation growing into or blowing into the conductor within the ROW, this shall be considered the equivalent of a Real-time observation. Brief encroachments caused by a falling tree going through the MVCD is not considered an encroachment."
Response: The SDT thanks you for your comments. The SDT is sympathetic to your concern. In fact, the SDT had originally crafted language similar to that which you suggested. However, due to concerns expressed by regulators and others, the exemption for encroachment violations due to falling vegetation from inside the right of way was removed.		
Arizona Public Service Company	No	The TO should be managing for reliability. The system is not static, like vegetation it moves and changes over time and that fluctuation should be taken into account to maintain reliability at all rated conditions.
Response: The SDT thanks you for your comments. The SDT agrees with your statement, and in that vein, the MVCD was established as a beginning of a series of "building blocks" for a program to ensure reliability within its rating and all rated electrical operating conditions. R3 requires that a TO add to MVCD distances with further considerations for the variables of conductor movement and the variables associated with vegetation growth when designing the TO's overall vegetation management approach(s). The net result of this "building block" approach is the management of vegetation at clearance distances much greater than the MVCD distances. Other related requirements of this "Defense in Depth" Standard serve to address any number of scenarios which may arise or hinder the TO's ability to always strictly adhere to the management approach(s) established within R3. Thus, the other requirements of this Standard provide the latitude for appropriate actions to remedy the condition without penalty. Further, trees which have encroached inside the MVCD are evidence of a deficiency in vegetation maintenance.		

Organization	Yes or No	Question 3 Comment
Salt River Project	Yes	
Tampa Electric Company	Yes	Confirmation allows for the potential of a greater number of “action items” than just investigation.
Response: The SDT thanks you for your comments. We agree that confirmation is necessary before an event is determined to be vegetation related.		
NextEra Energy	Yes	
SDG&E	Yes	
ASSET MANAGEMENET	Yes	
Hydro-Quebec TransEnergie (NCR07112)	Yes	
Kansas City Power & Light	Yes	
Manitoba Hydro	Yes	
Central Maine Power Company - IberdrolaUSA	Yes	
BC Hydro	Yes	
American Transmission Company, LLC	Yes	
American Electric Power	No	For increased clarity, AEP offers the following change to the second paragraph of M1, as well as the

Organization	Yes or No	Question 3 Comment
		second paragraph of M2. The original text “If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation” should be replaced with ““If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation growing into or blowing together with the conductor within the ROW, this shall be considered the equivalent of a Real-time observation. A brief encroachment caused by falling vegetation passing through the MVCD is not considered an encroachment in this requirement”.
Response: The SDT thanks you for your comments. The SDT is sympathetic to your concern. In fact, the SDT had originally crafted language similar to that which you suggested. However, due to concerns expressed by regulators and others, the exemption for encroachment violations due to falling vegetation from inside the right of way was removed.		
Baltimore Gas and Electric Co.	No	M1 & M2 bullet: “Real-time observation of any MVCD encroachments.” implies that real-time observation of vegetation encroachment ensures reliable operation the Bulk Electric System. The reliability standard objective states;”To improve the reliability of the electric Transmission system by preventing those vegetation related outages that could lead to Cascading.”However, real time observation of current operating conditions provides no assurance that vegetation will not lead to outages since it doesn’t take into consideration the full conductor range of motion including maximum sag. BGE recommends removing the language. If an inspector finds vegetation encroaching into the MVCD during a visual inspection he / she should immediately initiate an Immediate Threat Notification. Therefore, this measure has no value.
Response: The SDT thanks you for your comments. The SDT agrees with your statement and in that vein, the MVCD was established as a beginning of a series of “building blocks” for a program to ensure reliability within its rating and all rated electrical operating conditions. R3 requires that a TO add to MVCD distances with further considerations for the variables of conductor movement and the variables associated with vegetation growth when designing the TO’s overall vegetation management approach(s). The net result of this “building block” approach is the management of vegetation at clearance distances much greater than the MVCD distances. Other related requirements of this “Defense in Depth” Standard serve to address any number of scenarios which may arise or hinder the TO’s ability to always strictly adhere to the management approach(s)		

Organization	Yes or No	Question 3 Comment
established within R3. Thus the other requirements of this Standard provide the latitude for appropriate actions to remedy the condition without penalty. Further, trees which have encroached inside the MVCD are evidence of a deficiency in vegetation maintenance.		
TVA	Yes	
Niagara Mohawk Power Corporation (dba National Grid)	Yes	
CenterPoint Energy	Yes	
Duke Energy	Yes	However, this change was not completely made in paragraph five of the Guideline and Technical Basis document. There the phrase “an investigation” should be replaced by the phrase “a later confirmation”
Response: The SDT thanks you for your comments. The SDT made the suggested change.		
South Carolina Electric and Gas	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	
Individual		
Consolidated Edison Company of New York, Inc. - Transmission Line	Yes	

Organization	Yes or No	Question 3 Comment
Maintenance		
USACE	Yes	
CECD	No	Suggested Modification to the Measure - "If an after-the-fact analysis of a Fault by the Transmission Owner determines that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of observing an encroachment in Real-Time." CECD would also like to comment on the Evidence Retention section, as it relates to Measures. The Evidence Retention section states that the Transmission Owner retains data or evidence to show compliance with Requirement R1, R2, R3, R5, and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years...." Measures provide examples of evidence that a Transmission Owner can produce to show compliance with the associated Requirement but are not separate Requirements to be managed so reference to Measures should be deleted from the Evidence Retention section of the standard.
Response: The SDT thanks you for your comments. The SDT prefers to keep the existing language, which has been widely accepted by industry, since it is substantially the same as you suggest. With respect to the Evidence Retention section: The NERC evidence retention guidelines provided to SDTs recommend including a reference to the associated requirements and measures.		
Entergy Services, Inc	Yes	
Orange and Rockland Utilities, Inc.	Yes	
National Grid	Yes	
Western Electricity	Yes	

Organization	Yes or No	Question 3 Comment
Coordinating Council		
Georgia Transmission Corp.	Yes	
Northern Indiana Public Service Company	Yes	

4. **In response to comments received that requirement R3 is unclear with respect to intent, the SDT added "maintenance strategies". Do you agree this clarifies the intent? If answer is no, please offer alternative language.**

Summary Consideration: 36 responses were in agreement, 2 disagreed with no comments and 2 disagreements included comments.

A concern was raised with regard to using the MVCD as a distance "to manage a vegetation program" and asked the SDT to provide a buffer distance. The SDT explained that the MVCD was established as a beginning of a series of "building blocks" for a program to ensure reliability within its rating and all rated electrical operating conditions. R3 requires that a TO add to MVCD distances with further considerations for the variables of conductor movement and the variables associated with vegetation growth when designing the TO's overall vegetation management approach(s). The net result of this "building block" approach is the management of vegetation at clearance distances much greater than the MVCD distances. Other related requirements of this "Defense in Depth" Standard serve to address any number of scenarios which may arise or hinder the TO's ability to always strictly adhere to the management approach(s) established within R3. Thus the other requirements of this Standard provide the latitude for appropriate actions to remedy the condition without penalty. Further, trees which have encroached inside the MVCD are evidence of a deficiency in vegetation maintenance. A performance based standard is not prescriptive in nature but gives guidance to a TO on "what" to accomplish rather than "how" to accomplish it.

Another agreeable response requested R5 and R7 to include a relationship between the document that is developed for maintenance strategies and the annual work plan. The SDT explained that the references to the work plan in R5 and R7 are sufficient. The SDT considers maintenance strategies and work plans to be separate functions. Avoiding the reference to the work plans in R3 minimizes confusing the two functions.

One disagreement stated that the term "maintenance strategies" was not helpful and recommends the following: "Each Transmission Owner shall have a documented vegetation management plan that includes maintenance strategies, procedures, processes, and specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that include(s) the following:" The SDT notes that Requirement 3 is a results-based competency requirement and that having a TVMP as required in version 1 is simply a matter of having documentation, but there was no stipulation or concern for the quality of the TVMP as called for by version 1. In R3 of the revised Standard, the aspect of quality is introduced. The Transmission Owner must show that it has maintenance strategies in place that will logically keep vegetation from encroaching into the MVCD.

Another disagreement stated that the TVMP shall demonstrate the TO's ability to manage the system at all rated conditions to maintain reliability. The SDT agrees that this is the purpose of R3 and referenced the language in the rationale text for R3 clarifies - "... documentation provides a basis for evaluating the competency of the Transmission Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the Transmission Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. See Figure 1 for an illustration of possible conductor locations." A TVMP is one example of an approach to which this refers.

Organization	Yes or No	Question 4 Comment
SERC Vegetation Management sub-committee	Yes	
Hydro One Networks	Yes	
Northeast Power Coordinating Council	Yes	
Platte River Power Authority Substation Maintenance Group	Yes	
Bonneville Power Administration	Yes	The TO procedures / policies and specifications shall demonstrate the TO's ability to manage the system at all rated conditions to maintain reliability.BPA believes that the intent is clear, but the fundamental approach of using the MVCD (table 2) to manage a vegetation program is still problematic. These values are flashover distances and are way too close. This is acknowledged in a footnote to table 2 but no identification of allowable buffers/distances between energized phase conductors at rated temperatures and vegetation is discussed (this is left up the transmission owners). Clarity is needed on this topic. Setting a finite distance limit based on recognized standards, good science and risk avoidance should be done for the industry. BPA previously made this comment during the drafting of the standard. It was not addressed then, nor has it been

Organization	Yes or No	Question 4 Comment
		addressed now.
Response: The SDT thanks you for your comments. The SDT agrees with your statement, and in that vein, the MVCD was established as a beginning of a series of "building blocks" for a program to ensure reliability within its rating and all rated electrical operating conditions. R3 requires that a TO add to MVCD distances with further considerations for the variables of conductor movement and the variables associated with vegetation growth when designing the TO's overall vegetation management approach(s). The net result of this "building block" approach is the management of vegetation at clearance distances much greater than the MVCD distances. Other related requirements of this "Defense in Depth" Standard serve to address any number of scenarios which may arise or hinder the TO's ability to always strictly adhere to the management approach(s) established within R3. Thus the other requirements of this Standard provide the latitude for appropriate actions to remedy the condition without penalty. Further, trees which have encroached inside the MVCD are evidence of a deficiency in vegetation maintenance. A performance based standard is not prescriptive in nature but gives guidance to a TO on "what" to accomplish rather than "how" to accomplish it.		
NERC Staff	No	Adding the term "maintenance strategies" is not helpful in the requirement. NERC staff recommends the following: "Each Transmission Owner shall have a documented vegetation management plan that includes maintenance strategies, procedures, processes, and specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that include(s) the following:"
Response: The SDT thanks you for your comments. Requirement R3 is a results-based competency requirement. Having a TVMP as required in version 1 is simply a matter of having documentation. There was no stipulation or concern for the quality of the TVMP as called for by version 1. In R3 of the revised Standard, the aspect of quality is introduced. The Transmission Owner must show that it has maintenance strategies in place that will logically keep vegetation from encroaching into the MVCD.		
Pepco Holdings Inc and Affiliates	Yes	
FirstEnergy	Yes	
Dominion Electric Market	Yes	

Organization	Yes or No	Question 4 Comment
Policy		
Southern Company Transmission	Yes	
Arizona Public Service Company	No	The TVMP shall demonstrate the TO's ability to manage the system at all rated conditions to maintain reliability.
Response: The SDT thanks you for your comments. We agree that this is the purpose of R3. Please note the language in the rationale text for R3 clarifies - "... documentation provides a basis for evaluating the competency of the Transmission Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the Transmission Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. See Figure 1 for an illustration of possible conductor locations." A TVMP is one example of an approach to which this refers.		
Salt River Project	Yes	
Tampa Electric Company	Yes	Good addition, adds clarity and improves overall understanding of the requirement.
Response: The SDT thanks you for your comments.		
NextEra Energy	Yes	
SDG&E	Yes	
ASSET MANAGEMENET	Yes	
Hydro-Quebec TransEnergie (NCR07112)	Yes	

Organization	Yes or No	Question 4 Comment
Kansas City Power & Light	Yes	
Manitoba Hydro	Yes	
Central Maine Power Company - IberdrolaUSA	Yes	
BC Hydro	Yes	You could also include the term "maintenance standards".
Response: The SDT thanks you for your comments. Either word could work – however since most commenters agreed with the use of the word, 'strategies' the SDT did not adopt the suggestion to use the word, 'standards'.		
American Transmission Company, LLC	Yes	
American Electric Power	Yes	
Baltimore Gas and Electric Co.	Yes	
TVA	Yes	
Niagara Mohawk Power Corporation (dba National Grid)	Yes	
CenterPoint Energy	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 4 Comment
South Carolina Electric and Gas	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	This clearly defines “intent”.
Response: The SDT thanks you for your comments.		
Individual		
Consolidated Edison Company of New York, Inc. - Transmission Line Maintenance	Yes	
USACE	No	
CECD	Yes	Because Requirement 5 and 7 use the phrase annual work plan, and there is not a Requirement to develop a work plan, this Requirement should include a relationship between the document that is developed for maintenance strategies and the annual work plan.
Response: The SDT thanks you for your comments. The SDT considers the references to the work plan in R5 and R7 sufficient. The SDT considers maintenance strategies and work plans to be separate functions. Avoiding the reference to the work plans in R3 minimizes confusing the two functions.		
Entergy Services, Inc	Yes	

Organization	Yes or No	Question 4 Comment
Orange and Rockland Utilities, Inc.	Yes	
National Grid	Yes	
Western Electricity Coordinating Council	Yes	
Georgia Transmission Corp.	Yes	
Northern Indiana Public Service Company	No	

5. **The SDT added clarifying language in M7 to explain how the annual work plan percentage complete calculation is to be performed. Is this adequate? If no, please provide improved examples.**

Summary Consideration: There were 31 agreements and 8 disagreements. Seven comments noted that the question should have referenced R7 not M7. The SDT acknowledged that observation and agreed that the reference should have been R7. The SDT added the term "of applicable lines" to M7 and to the VSL's for R4, R5 and R6. The SDT also made minor changes to VSLs for R7 to conform to verbiage in R6.

One commenter agreed with R7 changes and noted "there is no requirement....that a plan is....developed." The SDT sees no reason to add such a requirement for documentation, since a fundamental precept of results-based standards is that having a requirement to complete any particularly activity also presupposes that the elements required to complete the activity are included in the requirement, even if unstated.

One affirmative comment requested that exceptions for crew performance and availability be noted explicitly: the SDT noted that while the requested condition could be listed, the list is not meant to be exhaustive, and that any modification to the work plan can be made provided it does not allow encroachment into the MVCD. The same commenter wished to include language related to derating the line to indicate that the purpose of such action would be to "ensure continued...reliability." The SDT saw problems associated with proving that a reliability contribution by a derating was in fact accomplished and chose to retain the existing language. The same commenter wished to remove Category 3 outage reporting, but the SDT sees great value in the investigation of each vegetation related outage and feels that this reporting is justified to ensure that all outages are sufficiently investigated. The same commenter requested removing the reference to "defense-in-depth" in the Background section; the SDT chose to leave this reference as is. Lastly that same commenter suggested that "promptly" could be substituted for "without intentional time delay" in R4, the SDT saw no difference in the two terms and chose to keep the existing verbiage.

A commenter suggested in lieu of the annual inspection requirement that a time interval based on growth rates be used instead. The SDT chose to retain the existing annual interval based on industry's consensus support for the one year interval in a previous posting of the Standard.

A commenter requested that "of applicable lines" be added to the requirements and VSL verbiage to clearly denote applicability within the requirements and VSL verbiage. The SDT made those changes as requested to the requirements, measures and VSLs. That same commenter requested that Category 3 outages be reported by type A & B similar to other categories. The SDT saw no value to this change since Category 3 serves its purpose without that distinction being made. The same commenter requested changes to the ROW definition; the SDT chose to retain the existing language since it has been vetted with significant industry consensus.

Another comment suggested adding reference to financial reports in the examples for reasons for modifications to the annual plan, the SDT feels that such a reference to financial conditions was inappropriate. The same commenter noted the need for clarity in the structure of the VSLs ; the SDT made those changes. The same commenter requested clarity on use of Table 2 when an entity has a voltage category not in the table - the team added language to clarify that where the TO has transmission lines operated at nominal levels not listed in Table 2, the TO should use the clearance distances based on the maximum system voltage (i.e. for a nominal system voltage of 287 kV the appropriate distances would be for a maximum system voltage of 362 kV). Two commenters requested an example be added to the Guidelines and Technical Basis section for R7, similar to the examples in R6, to clarify that the % calculations should be based on the Annual Plan as modified; the SDT added the example as requested.

Another commenter questioned the 48-hour reporting in the 12/17/2008 NERC Public Notice - NERC Compliance Process #2008-001. The SDT discussed the issue with NERC staff and did not receive any direction that it would be necessary to add this as a Requirement within the Standard

Additional comments were offered by NERC staff as a separate attachment to comments submitted with the comment form, and those responses are covered following this question.

Organization	Yes or No	Question 5 Comment
SERC Vegetation Management sub-committee	Yes	
Hydro One Networks	Yes	
Northeast Power Coordinating Council	No	There is no percentage language in M7. Is it R7 that is being referred to?
Response: The SDT thanks you for your comment. The SDT meant to refer to R7.		

Organization	Yes or No	Question 5 Comment
Platte River Power Authority Substation Maintenance Group	Yes	
Bonneville Power Administration	Yes	
NERC Staff	Yes	Actually, R7 contains the clarifying language. It should be noted that although R7 indicates the TO shall complete 100% of the VM work plan, there is no requirement in this draft that a plan is actually developed.
Response: The SDT thanks you for your comments. The SDT meant to refer to R7, not to M7. As to the seeming lack of an actual requirement for a work plan, the SDT asserts that a fundamental precept of results-based standards is that having a requirement to complete any particularly activity also presupposes that the elements required to complete the activity are included in the requirement, even if unstated.		
Pepco Holdings Inc and Affiliates	Yes	
FirstEnergy	Yes	Although we generally agree with Requirements R7 and its measure M7, we suggest adding clarifying wording to bullet 4 which states "Crew or contractor availability/ Mutual assistance agreements". In addition to availability, contractor performance may be another issue that requires modification to the work plan. We suggest adding another bullet that reads "Crew or contractor performance". The rationale behind this addition is to address poor safety, productivity and/or quality issues with a crew or contractor assigned to perform vegetation management.FirstEnergy provides the following additional comments and suggestions not related to the specific questions asked in this posting: 1. Requirement R5 - We appreciate this requirement which recognizes that the TO may face situations in which it is constrained from performing its vegetation management and are permitted

Organization	Yes or No	Question 5 Comment
		to seek alternative methods. However, there may be instances where the TO has exhausted all course of action to perform vegetation and must utilize other means to prevent vegetation encroachment into the MVCD. Therefore, in these instances, "continued vegetation management" as stated in the requirement is not possible, but other methods such as line deratings and deenergizing of lines may have to be used. We ask that the phrase "to ensure continued vegetation management to prevent encroachments" be changed to read “to ensure continued reliability of the BES”. 2. Compliance Section - Category 3 - We suggest removing this category from the standard. Since fall-ins from outside the ROW are not considered a violation of this standard per Requirements R1 and R2, the entity should not have to report these fall-ins. 3. Objectives - We do not believe that is necessary for the Objectives statement to include the "defense-in-depth" concept which is actually an overarching goal of results-based standards in general and not specific to FAC-003-2. We suggest removing this phrase. 4. Background Section 5 - Similar to our comment above regarding defense-in-depth in the objectives statement, this is an overarching goal of results based standard and not specific to FAC-003-2. Therefore, we suggest removing the explanation of defense-in-depth from the background section. 5. Vegetation Inspection Definition - We suggest replacing the word "hazard" with "risk". 6. Requirement R4 - We do not agree with the phrase "without any intentional time delay" and suggest it be removed. This phrase is not measurable. Also, other drafting teams have attempted to incorporate this statement but industry comments have persuaded them to remove it; for example, the Reliability Coordination drafting team (Project 2006-06) initially proposed the same phrase but later removed it in their development of the COM/IRO standards. At the very least standards development should be consistent throughout the NERC standards drafting teams. We suggest the following as wording for Requirement R7: "Each Transmission Owner shall ensure the control center holding switching authority for the applicable transmission line is promptly notified

Organization	Yes or No	Question 5 Comment
		when the Transmission Owner has confirmed the existence of a vegetation condition that can potentially cause a Fault."

Response: The SDT thanks you for your comments. The SDT considered your request to add to the acceptable reasons for modifications the bullet, "Crew or contractor performance," and observes that since R7 states "Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD)..." the bullet could be added, but the SDT did not intend the list of examples to be exhaustive and decided not to add the new bullet.

In reference to the comment 1) that the phrase "to ensure continued vegetation management to prevent encroachments" be changed to read "to ensure continued reliability of the BES," the SDT agrees that the corrective actions of de-ratings and de-energization as you suggest must be considered when vegetation cannot be maintained to prevent encroachment into the MVCD, and those examples are explicitly listed in M5. If a de-rating is used, it must be sufficient to prevent the encroachment into the MVCD. The de-rating or de-energization of the line removes the threat of an energized line and adjacent vegetation having less separation that the MVCD (i.e. less Fault probability), but the realized reliability value of those actions will depend on the events that occur while the condition persists. For these reasons the SDT retains the R5 language without changes.

In reference to the comment 2) "Compliance Section - Category 3 -...suggest removing this category from the standard," an investigation of the location of the tree with respect to the edge of the ROW for fall-ins must be made to determine whether the event represents a self-report of a violation or not. A record of those findings when the tree is found to be outside the ROW is valuable for both the Compliance Monitoring and Enforcement and the TO, should any questions later arise; therefore the SDT chose to retain the Category 3 reporting.

Regarding your comment 3) "Objectives - We do not believe that is necessary for the Objectives statement to include the "defense-in-depth" concept which is actually an overarching goal of results-based standards in general and not specific to FAC-003-2. We suggest removing this phrase." The SDT notes that the Purpose language is a general statement, and could be expanded or contracted without impacting the requirements. However, since the current language has undergone extensive debate, comment and revision the SDT sees no compelling reason to request industry to review another change at this time.

Regarding your comment 4) "Background Section 5 -.... suggest removing the explanation of defense-in-depth from the background section" The SDT notes again that the background section language is a general statement and could be expanded or contracted without impacting the requirements. However, since the defense-in-depth drove many of the changes in the standard the SDT thinks this section is relevant and should be retained.

Organization	Yes or No	Question 5 Comment
Regarding your comment 5) “suggest ...for Requirement R7(actually R4): "Each Transmission Owner shall ensure the control center holding switching authority for the applicable transmission line is promptly notified when the Transmission Owner has confirmed the existence of a vegetation condition that can potentially cause a Fault." The SDT has searched for but not found a time limit more suitable than “without intentional time delay.” An extensive list of event scenarios between the time that a condition is observed and the time it is reported can be studied. In the final analysis the intent is for the notification to be made to allow time for the control center to take steps to maintain reliability if possible before conditions deteriorate further. “Without intentional time delay” is as sufficient and as measurable as “promptly”.		
Dominion Electric Market Policy	No	The red-line revision does not indicated changes to M7; therefore, Dominion is unable to evaluate the clarifying language identified in this question. If the SDT meant to reference R7, we agree that the clarification is adequate.
Response: The SDT thanks you for your comments. The SDT means to reference R7.		
Southern Company Transmission	Yes	
Arizona Public Service Company	Yes	
Salt River Project	Yes	
Tampa Electric Company	Yes	This allows flexibility for the T.O. to determine the type of “unit” used in calculating the percentage complete.
Response: The SDT thanks you for your comments.		
NextEra Energy	Yes	
SDG&E	Yes	

Organization	Yes or No	Question 5 Comment
ASSET MANAGEMENET	Yes	
Hydro-Quebec TransEnergie (NCR07112)	No	The minimum frequency of Vegetation Inspection should be based upon an average growth rates of smaller regions than all North America. Example, above the latitude of about 50 degrees North, the vegetation growth rates is limited. We think that Vegetation Inspection frequency should be relaxed to 3 years for those areas in Canada. As indicator of the minimum frequency requested in R6, we suggest to use a global vegetation index like the Normalized Difference Vegetation Index (NDVI). The NDVI has been in use for many years to measure the vigor of vegetation growth among other things. http://earthobservatory.nasa.gov/Features/MeasuringVegetation/
Response: The SDT thanks you for your comments. In FERC Order 693, para. 721, FERC stated, “The Commission continues to be concerned with leaving complete discretion to the transmission owners in determining inspection cycles, which limits the effectiveness of the Reliability Standard.” The SDT established an inspection cycle at least once per calendar year and with no more than 18 months between inspections on the same ROW. There was a survey of the industry in a previous request for comments to this standard. The response to that survey is the basis for the use of the 1-year period. While there was a range of growth rates across the continent, the SDT had sufficient feedback to recommend the 1-year cycle. The inspection also would cover inspecting for fall-in threats. Please note that vegetation inspections can also be combined with other line inspections.		
Kansas City Power & Light	No	1) R7 states “Each Transmission Owner shall complete 100% of its annual vegetation work plan...”. We suggest to be consistent with all other sections of the rule that it should read, “Each Transmission Owner shall complete 100% of its annual vegetation work plan for all applicable lines...”. Otherwise, leaves room for interpretation to include all lines including those not defined as applicable. Also require these same revisions to row R7 of the table “Time Horizons, Violation Risk Factors, and Violation Severity Levels”. 2) In the “Additional Compliance Information” section Categories 1, 2, and 4 are each defined to have an A & B component to recognize the severity level difference for “applicable transmission lines” identified versus not identified “as an element of an IROL or Major WECC Transfer Path”. However, Category 3 does not separate these two scenarios however it appears that the same

Organization	Yes or No	Question 5 Comment
		distinction should apply. Additional comments:Vegetation Inspection Definition Recommend the SDT consider removing the conditional language, “that are likely to pose a hazard to the line(s) prior to the next”. Vegetation inspections are not dependent on a predisposed condition of vegetation. Suggest the SDT remove that phrase and consider the following definition:The systematic examination of vegetation conditions on a maintained transmission line Right-of-Way under the Transmission Owner’s control under a planned maintenance or inspection which may be combined with a general line inspection.
Response: The SDT thanks you for your comments. 1) The team has made the appropriate modifications, adding the reference to ‘applicable lines’ where necessary. 2) Since the Category 3 outages do not have any violations associated with their occurrences, the SDT did not see the value in reporting by type A or type B lines. 3) The SDT chooses to keep the current language because it addresses the core need to find conditions that will need correcting before the next planned maintenance or next planned inspection is performed.		
Manitoba Hydro	Yes	
Central Maine Power Company - IberdrolaUSA	Yes	
BC Hydro	Yes	You could also include other documentation such as monthly financial and program variance reports. Additional Comments Table 1: R6 definitions could be clearer. Suggested clarification: VSL Lower - Greater than 95% of annual inspections complete but less than 100% complete. VSL Moderate - Greater than 90 % of annual inspections complete but less than 95% complete VSL High - Greater than 85% of annual inspections complete but less than 90% complete VSL Severe - Less than 85% of annual inspections completed

Organization	Yes or No	Question 5 Comment
		Table 1 R7 definitions could be clearer. Suggested clarification: VSL Lower - Greater than 95% of annual work plan complete but less than 100% complete. VSL Moderate - Greater than 90 % of annual work plan complete but less than 95% complete VSL High - Greater than 85% of annual work plan complete but less than 90% complete VSL Severe - Less than 85% of annual work plan completed Table 2: This table includes a number of common nominal system voltages vs MVCD distances by altitude. However, some utilities have other non-standard voltages, in our case 287 kV, which forms a significant part of their system. It may be worthwhile for the standard to state what a utility should follow when a standard voltage class is not present - i.e. go to the next higher voltage MVCD if a particular voltage isn't in the table, or direct the utility to do its own Gallett Equation calcuations for their unique voltage class. Otherwise, different utilities may create a non-standard solution that wouldn't address the risk.
Response: The SDT thanks you for your comments. The SDT did not intend for the list of examples to be exhaustive. To the extent that financial or variance reports include evidence of the work units completed they may be useful as supportive evidence. inappropriate. The SDT used the NERC VSL Guidelines to develop the VSLs; therefore the SDT feels that the VSL's for R7 are adequate as listed. The proposed VSLs would leave some 'gaps' – for example the proposed VSLs aren't clear on what VSLs is assigned when an entity has completed exactly 95% of its inspections. Table 2 in the Standard lists both the nominal system voltages and the corresponding maximum system voltages. The clearance distances listed for each nominal system voltage were calculated using the maximum system voltage values. Therefore, where the TO has transmission lines operated at nominal levels not listed in Table 2, the TO should use the clearance distances based on the maximum system voltage (i.e. for a nominal system voltage of 287 kV the appropriate distances would be for a maximum system voltage of 362 kV). The SDT has added language to the guidelines and technical basis section to clarify this point.		
American Transmission	Yes	

Organization	Yes or No	Question 5 Comment
Company, LLC		
American Electric Power	Yes	
Baltimore Gas and Electric Co.	Yes	
TVA	No	I suggest that footnote 4 be changed by removing the reference to arbicultural, horticultural or agricultural activities.
Response: The SDT thanks you for your comments. The recommended changes have been made to footnote 4.		
Niagara Mohawk Power Corporation (dba National Grid)	No	There is currently no percentage language in M7. If they are referring to R7, then YES it is adequate.
Response: The SDT thanks you for your comments. The question should have referred to R7.		
CenterPoint Energy	No	CenterPoint Energy could not find any reference to an example percentage complete calculation for the annual work plan in the Standard for M7, in the Guideline and Technical Basis for M7, nor in the Technical Reference for M7. There was such an example for M6 which was helpful. CenterPoint Energy recommends such an example be included for M7.
Response: The SDT thanks you for your comments. The percentage complete should be based on the annual plan as modified. The SDT has changed the language in the standard to reflect more clearly that the percentage complete should be based on the plan as modified, and the following example has been added to the Guideline and Technical Basis: For example, when a Transmission Owner identifies 1,000 miles of 230 kV transmission lines to be completed in the TO's annual plan, the Transmission Owner will be responsible completing those identified miles. If a TO makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage the TO completed for the current year would be: 1000 – 100 (deferred miles) = 900 modified annual		

Organization	Yes or No	Question 5 Comment
plan, or 900 / 900 = 100% completed annual miles. If a TO only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: 1000 – 875 = 125 miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12% failed to complete.		
Duke Energy	Yes	
South Carolina Electric and Gas	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	This is directed toward R7 rather than M7.
Response: The SDT thanks you for your comments.		
Individual		
Consolidated Edison Company of New York, Inc. - Transmission Line Maintenance	Yes	The added language for the annual work plan percentage complete calculation is shown in R7 not M7 as stated in the question. In the Guideline and Technical Basis Section for Requirement R6, there is a sample calculation shown for the amount of lines the TO failed to inspect. An example should also be included for Requirement R7 since there is some confusion regarding how modifications to the work plan affect the calculation. In the Lower VSL column for R7, it states that the TO failed to complete up to 5% of its annual vegetation work plan (including modifications if any). If a TO operates 100 lines and submits a justified modification that affects 10 miles of lines, the total number of units in the final amended plan is 90 miles. When you read the VSL, it is somewhat confusing since the information in parenthesis says that the calculation 'includes' the modifications. Should it state 'excludes modifications if any' or the VSLs can simply be re-written to state that ..The TO failed to complete up to x% of the final amended plan.' Also, the VSLs in R6 and

Organization	Yes or No	Question 5 Comment
		R7 should be consistent with each other: R6 says '...TO failed to inspect 5% or less.....' and R7 says '...TO failed to complete up to 5%....' They both should use the same verbiage in each VSL whether it is 'x% or less' or 'up to and including x%.'
Response: The SDT thanks you for your comments. The percentage should be based on the plan as modified. The SDT has changed the language in the standard to reflect this more clearly.		
USACE	Yes	
CECD	Yes	
Entergy Services, Inc	Yes	The actual clarifying language seems to have been added to R7 instead of M7 (as stated above). The clarifying language provides benefit as added to R7, and should remain in R7.Additionally, we feel that, in an effort to promote consistency with the other 6 Requirements, the term "on applicable Transmission lines" should be added at the end of the first sentence of R7, as it is listed in all other R's. The first sentence of R7 currently reads: "Each Transmission Owner shall complete 100% of its annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD". We feel the first sentence should read "Each Transmission Owner shall complete 100% of its annual vegetation work plan to ensure no vegetation encroachments occur within the MVCD on applicable transmission lines".
Response: The SDT thanks you for your comments. The first sentence does now contain the term “applicable lines”.		
Orange and Rockland Utilities, Inc.	Yes	
National Grid	No	There is currently no percentage language in M7. If they are referring to R7, then YES it is adequate.

Organization	Yes or No	Question 5 Comment
Response: The SDT thanks you for your comments. The SDT was referring to R7.		
Western Electricity Coordinating Council	Yes	We support the clarifying languae in M7However, since there is no generic "Any other Comments" section associated with this on-line comment form, we raise a question here. On December 24, 2008, NERC issued an e-mail to all Transmission Owners in which it referenced its December 17, 2008 Public Notice - NERC Compliance Process #2008-001, Vegetation-related Transmission Outage Reporting. The notice stated that: "Due to the potential severity of transmission outages caused by vegetation associated with Standard FAC-003-1, NERC is encouraging each Transmission Owner to self-report all Category 1 and Category 2 transmission outages related to vegetation to the Regional Entity within 48 hours utilizing the 48-hour vegetation reporting notice form provided by your appropriate Regional Entity."We do not see any reference to a 48-hour reporting notice in lthis version of the standard. Is this still a requirement? The only reference to reporting is in the Additional Compliance Information section and references quarterly reporting only.
Response: The SDT thanks you for your comments. The SDT is aware of the 48 hour, voluntary self-report request from NERC for outages where vegetation may be involved. The SDT also agrees with the general philosophy proposed by WECC that all requirements associated with a Standard are best served in the Standard. Also, the SDT did examine the general concept of an "investigation" type requirement. However, the SDT did not pursue this because it did not satisfy the basic rule for requirements as embedded in the Standards Process Manual, "What functional entity shall do what under what conditions to achieve what reliability objective." After the fact investigation and reporting, while important to the Compliance and Enforcement (CMEP) aspect of mandatory and enforceable Standards, does not achieve a reliability objective such that the failure to comply with the Requirement would jeopardize reliability. The SDT also notes that any useful (other than CMEP) information related to an outage that is subsequently reported under the NERC voluntary request would generally be available for industry use through TADS. Finally, the SDT did discuss the issue with NERC staff and did not receive direction that it was necessary, or desirable, to include one or more elements of the voluntary request in this Standard.		
Georgia Transmission Corp.	Yes	
Northern Indiana Public	Yes	

Organization	Yes or No	Question 5 Comment
Service Company		

Additional Comments from NERC:

In addition to the comments NERC submitted to the five questions on the official comment form, NERC staff has numerous other comments to make with regard to this Draft 5. Before that, NERC staff first wants to acknowledge the significant effort and talent that the industry brought to attempt to improve upon Reliability Standard FAC-003-1 – Vegetation Management. This Draft 5 of FAC-003-2 – Vegetation Management entailed significant industry work towards understanding the issue, compromising on proposals and attempting to reach consensus utilizing the NERC Standards Development Process. While NERC staff believes this draft represents some improvements to the existing standard, it does not believe the draft in its totality represents an improvement to the existing standard. FERC Order 693 approved the existing Vegetation Management Standard and it provided a number of directives for NERC with regard to further developing the Standard in order to improve it. Such directives and NERC comments regarding how the directives were addressed included:

- FERC Directive - Develop compliance audit procedures, using relevant industry experts, which would identify appropriate inspection cycles based on local factors. The Commission is dissuaded from requiring the ERO to create a backstop inspection cycle at this time.

  NERC Comment – Compliance audit procedures are outside the scope of the SDT and this Draft 5. Although not required by the Commission, the SDT added an annual inspection cycle to the Standard, with a maximum of 18 months between inspections. NERC believes this requirement represents an improvement to the existing Standard and does not believe it is overly burdensome on utilities.

Response: The SDT thanks you for your comments.

- FERC Directive - Remove the general limitation on lines 200kV and above to include lines that have an impact on reliability.
  - Do not reduce facilities included
  - Develop an acceptable definition for the applicability of this Reliability Standard that covers facilities that impact reliability while not unreasonably increasing the burden on transmission owners.
  - Evaluate the suggestions proposed by LPPC, APPA and Avista that regional entities should determine which facilities this standard applies to

  NERC Comment – NERC believes Draft 5 partially addresses this issue by increasing applicable facilities to IROL lines under 200kV. NERC staff is also concerned about

- The possibility that this very addition could limit a regional entity's desire to include additional lines.
- The exclusion of facilities inside the fenced area of switching stations, stations and substations. These excluded areas still pose a vegetation related outage risk and the rationale for excluding them is not compelling enough.
- The separation of IROL (any voltage level) and non-IROL (200 kV and above) Transmission Lines into separate requirements with different VRFs. NERC believes all Transmission Lines subject to this standard should be under the same requirement and associated VRFs. IROL lines are relatively few and do not warrant their own requirement. By having lower VRFs for non-IROL lines, this version of the standard is weaker than the existing standard. These two requirements should be a single requirement with high VRFs

Response: The SDT thanks you for your comments. In the guidelines provided by NERC to the drafting team, the SDT is dissuaded from writing 'fill in the blank' requirements. In version one, the team directed the RO to designate which critical lines below 200kV should fall under the standard without defining what critical meant. This is a 'fill-in-the- blank.' There is no assurance that this applicability would be applied consistency across North America. The SDT followed FERCs suggestion to take into account "…the suggestions by Progress Energy, SERC and MISO to limit applicability to lower voltage lines associated with IROL…" The team went further by including WECC transfer paths. The SDT asserts that the inclusion of both IROL lines and WECC Transfer paths addresses the comments by LPPC, APPA and Avista along with Progress Energy, SERC and MISO. The NERC Staff needs to consider that the comments all contend that each inclusion of a below 200kV line is an added burden to the rate payers. Not to give some direction to the Planning Coordinator would allow a planner to include ALL transmission lines, which would be an unreasonable burden to the rate payer. We added this language for clarity at the request of stakeholder concerns.

Neither the standard nor its original SAR were intended to cover fenced or discrete locations such as substations, which entail entirely different issues compared to linear corridors. Often substations are owned by either DPs or GOs, therefore, the TO may not have rights inside the fenced facility. The requirements in this standard would not be sufficient to include stations and switch yards. Should there be a compelling need for a vegetation standard for fenced facilities, a new SAR should be introduced.

The SDT asserts that different VRF's for IROL and non-IROL lines strengthens the reliability of the standard. Vegetation managers that do not know which lines are IROL or WECC Transfer Paths may be inappropriately limiting resources allocated to vegetation management for an IROL line or a WECC Transfer Path. A vegetation manager must ensure that the IROL lines and WECC transfer paths are absolutely clear. By correctly identifying the risk associated with an IROL line and/or a WECC Transfer Path, the standard helps to assure that appropriate resources are applied.

VRF guidelines require an analysis of impact to BES. We did that by considering the relative risk levels to the interconnected transmission system of an interruption of a non-IROL/non-Transfer Path line versus the interruption of IROL/Transfer Path lines. The fact that the PENALTY might be higher or lower DOES NOT AFFECT the strength or weakness of the Standard, since even the Medium Risk Factor value in the Base Penalty Matrix in the sanctions guidelines is $350,000 per violation per day. In both R1 and R2 of Version 2 there is zero-tolerance for encroachments, and Version 2 increases the scope to include observed encroachments without Faults, and confirmed vegetation Faults without Sustained Outages which were not clearly included in Version 1. The 1) distinction by separation of VRFs and 2) inclusion of clear language to inspect for, investigate, correct, and report to all known reliability threats will strengthen the standard.

- FERC Directive - Develop a Reliability Standard that defines the minimum clearance needed as an improvement to IEEE 516 which FERC does not believe is appropriately used for purposes of reliability and/or safety.

  NERC Comment – Draft 5 makes a change from IEEE 516 and utilizes Gallet equations for industry clearances. While NERC believes these equations are technically accurate, NERC is concerned about the usefulness of the clearances determined under this methodology as put forth in this draft. NERC is not aware of any utility which would maintain clearances as specified in this draft as it has no built in safety factor. NERC is further concerned that utilities could be mandated by courts of law to reduce existing maintained clearances to values much closer to those determined by the methodology in this draft.

Response: The SDT thanks you for your comments. As with a Transmission Owner's determination of its Clearance 1 distances under version 1 of the Standard, Requirement 3 of the revised Standard begins with the MVCD distances (just as Clearance 1 began with IEEE-516 distances) and then requires additional consideration for conductor movement, vegetation growth variables, and the utility's maintenance approach. These are essentially the same considerations required by version 1 of the existing Standard when developing Clearance 1 distances. Therefore, nothing has been "lost" in the revised Standard. In fact, the proposed Standard is better from an auditing perspective because the overall logic and rationale used by the TO in complying with the new Requirement 3 is now subject to an overall test of adequacy, competency and reasonableness. Also, informal polls conducted by the SDT show that many Transmission Owners are unsuccessful in utilizing Clearance 1 as a tool, because it is easily challenged by landowners as being an arbitrary fill-in-the-blank value set by the Transmission Owner. Further, if the Transmission Owner would cut only to Clearance 1 instead of to the full extent of its legal rights, courts could rule against the Transmission Owner for failing to exercise its full legal rights. Thus, in the revised Standard, the Transmission Owner has neither gained nor lost any tool or advantage in dealing with landowners, but the SDT asserts that the bar has been raised with regard to the adequacy of the Transmission Owner's overall vegetation management program.

- FERC Directive - Define rights-of-way to encompass the required clearance areas instead of the corresponding legal rights, and the standards should not require clearing the entire right-of-way when the required clearance for an existing line does not take up the entire right-of-way.

  NERC Comment – NERC staff believes this directive was met and is addressed in question 1 of the comment form.

Response: The SDT thanks you for your comments.

- FERC Directive – NERC should address the proposed modifications through its Reliability Standards development process.

  NERC Comment – NERC staff believes this directive was met in preparing this draft standard.

Response: The SDT thanks you for your comments.

- FERC Directive - Collect outage data for transmission outages, analyze it, and use the results of this analysis and information in the development of the Reliability Standard.

  NERC Comment – NERC staff believes more work needs to be done in this area. NERC staff believes the drafting team should consider modifying the Periodic Data Submittal to include if outages occur on Federal land.

Response: The SDT thanks you for your comments. After discussion with NERC staff, NERC has agreed to address this issue outside the work of the SDT. The SDT recommends that NERC staff consider adding a field to the TADS data to capture vegetation outages on applicable lines on federal lands.

Other Draft 5 Issues

- Removal of a formal transmission vegetation management program, of Clearance 1 and of a documented vegetation management plan.

NERC Comment – NERC does not support the removal of these items. NERC does not believe these changes represent an improvement to the standard and does not believe this existing requirement is overly burdensome to utilities. NERC does not understand why industry would not be willing to be held accountable to their vegetation management plans. NERC is concerned that the removal of these items could make it difficult for utilities to obtain permissions needed to maintain clearances between inspection cycles which are prudent for reliability and safety due to intervener or landowners exercising their rights and then pointing to this new standard as a the basis for smaller clearances. . Requirement 3 in this draft needs to include a documented plan and to clearly identify the specifics to be included in the plan and provide clarity of expectations. The SDT may not support such specifics as not being consistent with results-based standards development but NERC staff believes otherwise.

Response: The SDT thanks you for your comments. The existing series of items in Requirement R3 along with R3.2 are collectively with the balance of the standard equivalent to the term TVMP. These combined items in R3 are the defense in depth approach that require the TO to maintain vegetation so that it does not enter into the MVCD before the next planned vegetation work, thus accomplishing the equivalent of a C1 without a fill-in-the-blank issue.

- Objectives**:** A qualifier in the standard Objective that it should apply to preventing the risk of vegetation related outages *that could lead to cascading outages.*

  NERC Comment – This qualifier limits the purpose of the standard, which should be to prevent vegetation related outages, not cascading outages. The more outages there are, the less the overall system reliability. An outage does not necessarily have to lead to a cascading outage to be significant and represent a reasonable risk to the BES. References to cascading outages should be removed.

Response: The SDT thanks you for your comments. The SDT has thoughtfully considered every aspect of this version of the Standard to ensure that the pieces are consistent, aligned, and support each other. The SDT added the phrase "with Cascading" not to limit the Standard, but rather to recognize that the 200 kV bright-line for applicability (which is not in question) is founded on the very notion that the 200 kV serves as a proxy for "The Big Three": Cascading, Separation, and Instability. The SDT considered adding all of these conditions to the Purpose statement. However, given the focus of this Standard is on vegetation, and vegetation was deemed to be related to Cascading (i.e. 2003 Blackout report), rather than the other two undesirable system conditions, it seemed more logical and consistent to include the likely outcome of an unmanaged vegetation condition on a Transmission Owner's system. If NERC Staff has evidence that other two are likely related to vegetation, it has not yet been provided to the SDT.

Unlike other types of outages on lines (such as those caused by failed insulators, broken cross-arms, rotten poles and lightning flashover), vegetation outages uniquely affect lines when they are heavily loaded and thus susceptible to a cascading event.

- Background**:** This section excludes vegetations fall-ins and blow-ins from outside the ROW on the basis that they are not preventable.

  NERC Comment – Many fall-ins and blow-ins from outside the ROW are preventable. Trees outside the ROW must be managed adequately to prevent outages on the BES. The work to remove and/or prune trees outside the ROW may be more difficult and costly than such work inside the ROW, but that is not sufficient reason to exclude this work. In addition, utilities wishing to perform such work might be prevented from doing so by regulatory bodies based upon the lack of a specific requirement in this standard.

Response: The SDT thanks you for your comments and has reworded the Background by removing the term non-preventable.

- Requirement 1 & 2: These requirements discuss preventing encroachments into the MVCD of an applicable line that is operating within its Rating.

  NERC Comments –NERC staff would like confirmation that "Rating" is intended to include all published ratings issued by the facility owner, such as Normal, Emergency, etc.

Response: The SDT thanks you for your response. The glossary term “Rating” is adequate to address the issues you raise.

- Requirement 4: R4 states that “Each Transmission Owner, without any intentional time delay, shall notify…”

  NERC Comments: The previous version of the standard included a time limit of 15 minutes once communications became available. This should be reinstated.

Response: The SDT thanks you for your response. The SDT is not aware any posting with a 15 minute rule included.

- Requirement 7: R7 sets the requirement for each Transmission Owner to complete 100 percent of its annual vegetation work plan.

  NERC Comments – NERC is concerned that the draft doesn’t have a requirement for a Transmission Owner to have a documented annual plan making Requirement 7 unenforceable. In addition, Requirement 7 has a number of other qualifiers that would seem to allow manipulation of the annual plan to ensure compliance.

Response: The SDT thanks you for your comments. The SDT asserts that a fundamental precept of results-based standards is that having a requirement to complete any particularly activity also presupposes that the elements required to complete the activity are included in the requirement, even if unstated.

- Draft 5 document quality

  NERC Comments – this draft has some typographical errors which need to be fixed. For example, on page 28, reference to use of Table 5 versus Table 7 based on knowledge of maximum transient over-voltage factor is reversed. These edits could probably be handled through a recirculation ballet.

Response: The SDT thanks you for your comments. We agree with the typo you found and we have changed the language in the draft standard.

- Previously raised NERC issues

  NERC Comments – NERC staff posted several comments on the Draft 4 version of this standard in July 2010. NERC believes most of the concerns it raised in those comments are not addressed in Draft 5 and continue to be a concern for NERC.

Response: The SDT thanks you for your comments; however there are not enough specifics for the SDT to respond.

- General compliance and audit issues

  NERC Comments –

  - The whole "sustained outage" concept in R1 (for fall ins and blow ins) is unworkable from an enforcement perspective.
  - The difference between a violation and a non-violation in Draft 5 is whether the registered entity was fortunate with regard to an encroachment. This part should be rewritten to say that any tree contact is a violation. VRFs and VSLs could then be used to address whether the violation was minor or serious.
  - There could be a lot of litigation over whether "circumstances" were really "beyond the control" of the TO. NERC had previously objected to the implementation of a force majeure clause in the standard. If an entity failed to carry out its annual plan, that should be treated as a violation, and any excuses for failing to do so or for changing the plan mid-year all go to whether the penalty should be $0 or substantial.
  - For the evidence retention period, the entity really should retain evidence of compliance until the next compliance audit. Since some TOs may be on a 6 year audit schedule, the 3 year retention period is not sufficient.

Response: The SDT thanks you for your comments.

- The SDT does not understand your comment. The violations under the existing standards are largely due to sustained outages.
- Version 2 has a violation for every known and confirmed encroachment. The Penalty for those encroachments that do no cause Faults is up to $30,000 per violation per day
- The SDT thanks you for your comments. The SDT believes this language is appropriate for this standard due to the many factors related to vegetation that are truly outside the TO's control. Unlike the vast majority of other NERC standards, implementation of FAC-003 is not under

the absolute control of the utilities. These influences range from landowner and agency obstacles to weather events, and as such the SDT believes the force majeure provisions should be applicable. The recognition of this provision is also supported by 90% of the industry. An attempt at similar language is contained in version 1 but it is ambiguous and lacks clarity. This language adds clarity and reduces the opportunity for misapplication. Further, TO's must have supporting evidence for claims that situations are "beyond their control".

- The SDT thanks you for your comments, and will use the NERC approved retention times.

End of Report

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SC approved SAR for initial posting (January 11, 2007).
2. SAR posted for comment (January 15–February 14, 2007).
3. SAR posted for comment (April 10–May 9, 2007).
4. SC authorized moving the SAR forward to standard development (June 27, 2007).
5. First draft of proposed standard posted (October 27, 2008-November 25, 2008)).
6. Second draft of revised standard posted (September 10, 20-October 24, 2009).
7. Third draft of revised standard posted (March 1, 2010-March 31, 2010).
8. Fourth draft of revised standard posted (June 17, 2010-July 17, 2010).
9. Fifth draft of revised standard posted (February 18, 2011-February 28, 2011)
10. Sixth draft of revised standard posted (September xx - 2011)

Proposed Action Plan and Description of Current Draft

This is the fourth posting of the proposed revisions to the standard in accordance with Results-Based Criteria and the sixth draft overall.

Future Development Plan

Anticipated Actions	Anticipated Date
Recirculation ballot of standards.	September 2011
Receive BOT approval	November 2011

Effective Dates

This standard becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval is required. Where no regulatory approval is required, the standard becomes effective on the first calendar day of the first calendar quarter one year after Board of Trustees adoption.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.

2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.

3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.

4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.

5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

Version History

Version	Date	Action	Change Tracking
1	TBA	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	01/20/06
1	April 4, 2007	Regulatory Approval — Effective Date	New
2			

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Right-of-Way (ROW)

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.

The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

Vegetation Inspection

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.

Current definition of Vegetation Inspection: The systematic examination of a transmission corridor to document vegetation conditions.

Minimum Vegetation Clearance Distance (MVCD)

The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.

A. Introduction

1. **Title:** Transmission Vegetation Management

2. **Number:** FAC-003-2

3. **Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

4. **Applicability**

4.1. Functional Entities:

4.1.1 Transmission Owners

4.2. Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities:

4.2.1. Each overhead transmission line operated at 200kV or higher.

4.2.2. Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.

4.2.3. Each overhead transmission line operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC.

4.2.4. Each overhead transmission line identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

Rationale: The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) NERC has a project in place to address at a later date the applicability of this standard to Generation Owners. 4) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies."*

Enforcement:
The Requirements within a Reliability Standard govern and will be enforced. The Requirements within a Reliability Standard define what an entity must do to be compliant and binds an entity to certain obligations of performance under Section 215 of the Federal Power Act. Compliance will in all cases be measured by determining whether a party met or failed to meet the Reliability Standard Requirement given the specific facts and circumstances of its use, ownership or operation of the bulk power system.

Measures provide guidance on assessing non-compliance with the Requirements. Measures are the evidence that could be presented to demonstrate compliance with a Reliability Standard Requirement and are not intended to contain the quantitative metrics for determining satisfactory performance nor to limit how an entity may demonstrate compliance if valid alternatives to demonstrating compliance are available in a specific case. A Reliability Standard may be enforced in the absence of specified Measures.

Entities must comply with the “Compliance” section in its entirety, including the Administrative Procedure that sets forth, among other things, reporting requirements.

The “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” are provided for informational purposes. They are designed to convey guidance from NERC’s various activities. The “Guideline and Technical Basis” section and text boxes with “Examples” and “Rationale” are not intended to establish new Requirements under NERC’s Reliability Standards or to modify the Requirements in any existing NERC Reliability Standard. Implementation of the “Guideline and Technical Basis” section, the Background section and text boxes with “Examples” and “Rationale” is not a substitute for compliance with Requirements in NERC’s Reliability Standards.”

5. **Background:**

This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

a) Performance-based — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system <u>performance result or outcome</u>*?

b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome <u>that reduces a stated risk</u> to the reliability of the bulk power system*?

c) Competency-based — defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what*

> *conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system*?

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term "public lands" includes municipal lands, village lands, city lands, and a host of other governmental entities.

This standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

B. Requirements and Measures

R1. Each Transmission Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[2] [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage[3],
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage[4],
3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[4],
4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage[4].

Rationale for R1 and R2:
Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a Transmission Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.

2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.

3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.

4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

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[2] This requirement does not apply to circumstances that are beyond the control of a Transmission Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

[3] If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

[4] Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

M1. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

R2. Each Transmission Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[2] [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD, observed in Real-time as shown in FAC-003-Table 2, absent a Sustained Outage[3],
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage[4],
3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[4],
4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage[4]

M2. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)

R3. Each Transmission Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that accounts for the following:

3.1 Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions;

3.2 Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

[*Violation Risk Factor: Lower*] [*Time Horizon: Long Term Planning*]:

Rationale

The documentation provides a basis for evaluating the competency of the Transmission Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the Transmission Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. See Figure 1 for an illustration of possible conductor locations.

M3. The maintenance strategies or procedures or processes or specifications provided demonstrate that the Transmission Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

R4. Each Transmission Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the Transmission Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time*].

Rationale

This is to ensure expeditious communication between the Transmission Owner and the control center when a critical situation is confirmed.

M4. Each Transmission Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When a Transmission Owner is constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the Transmission Owner shall take corrective action to ensure continued vegetation management to prevent encroachments [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

Rationale

Legal actions and other events may occur which result in constraints that prevent the Transmission Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the Transmission Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

M5. Each Transmission Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that the line was de-energized. (R5)

R6. Each Transmission Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW[5] [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

Rationale

Inspections are used by Transmission Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

[5] When the Transmission Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO is granted a time extension that is equivalent to the duration of the time the TO was prevented from performing the Vegetation Inspection.

M6. Each Transmission Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each Transmission Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

Rationale

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of a Transmission Owner[6]
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

M7. Each Transmission Owner has evidence that it completed its annual vegetation work plan for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

[6] Circumstances that are beyond the control of a Transmission Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or an applicable regulatory body.

C. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

1.2 Regional Entity Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaint

Periodic Data Submittal

1.4 Additional Compliance Information

Periodic Data Submittal: The Transmission Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the Transmission Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.
- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by Transmission Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High	The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.	The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD due to a grow-in that caused a vegetation-related Sustained Outage.
R2	Real-time	Medium	The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.	The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.	The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD due to a grow-in that caused a vegetation-related Sustained Outage.
R3	Long-Term Planning	Lower		The Transmission Owner has maintenance strategies or documented procedures or processes or specifications but has not accounted for the inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the Transmission Owner's	The Transmission Owner has maintenance strategies or documented procedures or processes or specifications but has not accounted for the movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the Transmission Owner's	The Transmission Owner does not have any maintenance strategies or documented procedures or processes or specifications used to prevent the encroachment of vegetation into the MVCD, for the Transmission Owner's applicable lines.

				applicable lines. (Requirement R3, Part 3.2)	applicable lines. Requirement R3, Part 3.1)	
R4	Real-time	Medium			The Transmission Owner experienced a confirmed vegetation threat and notified the control center holding switching authority for that applicable line, but there was intentional delay in that notification.	The Transmission Owner experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that applicable line.
R5	Operations Planning	Medium				The Transmission Owner did not take corrective action when it was constrained from performing planned vegetation work where an applicable line was put at potential risk.
R6	Operations Planning	Medium	The Transmission Owner failed to inspect 5% or less of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The Transmission Owner failed to inspect more than 5% up to and including 10% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The Transmission Owner failed to inspect more than 10% up to and including 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The Transmission Owner failed to inspect more than 15% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7	Operations Planning	Medium	The Transmission Owner failed to complete 5% or less of its annual vegetation work plan for its applicable lines (as finally modified).	The Transmission Owner failed to complete more than 5% and up to and including 10% of its annual vegetation work plan for its applicable lines (as finally modified).	The Transmission Owner failed to complete more than 10% and up to and including 15% of its annual vegetation work plan for its applicable lines (as finally modified).	The Transmission Owner failed to complete more than 15% of its annual vegetation work plan for its applicable lines (as finally modified).

D. Regional Differences

None.

E. Interpretations

None.

F. Associated Documents

Guideline and Technical Basis (attached).

Guideline and Technical Basis

Effective dates:

The first two sentences of the Effective Dates section is standard language used in most NERC standards to cover the general effective date and is sufficient to cover the vast majority of situations. Five special cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the standard.

Case 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the Transmission Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.

Date that Planning Study is completed	PY the line will become an IROL element	Date 1	Date 2	Effective Date The latter of Date 1 or Date 2
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Case 2 is needed because a line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Case 3 is needed because a line operating at 200 kV or above that once was designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.

Case 4 is needed because an existing line that is to be operated at 200 kV or above can be acquired by a Transmission Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the Transmission Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network which will thereafter make the line subject to the standard.

Case 5 is needed because an existing line that is operated below 200 kV can be acquired by a Transmission Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the Transmission owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network. In this special case the line upon acquisition was designated as an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC Transfer Path.

Defined Terms:

Explanation for revising the definition of ROW:
The current NERC glossary definition of Right of Way has been modified to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of “right of way” in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the revised definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

Explanation for revising the definition of Vegetation Inspections:
The current glossary definition of this NERC term is being modified to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

Explanation of the definition of the MVCD:
The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 below provides MVCD values for various voltages and altitudes. Details of the equations and an example calculation are provided in Appendix 1 of the Technical Reference Document.

Requirements R1 and R2:
R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each Transmission Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element of an IROL or Major WECC Transfer Path. R2 is applicable to all other lines that are <u>not</u> elements of IROLs, and <u>not</u> elements of Major WECC Transfer Paths.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or a Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not elements of IROLs or Major WECC Transfer Paths do require effective vegetation management, but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

Requirements R1 and R2 state that if inadequate vegetation management allows vegetation to encroach within the MVCD distance as shown in Table 2, it is a violation of the standard. Table 2 distances are the minimum clearances that will prevent spark-over based on the Gallet equations as described more fully in the Technical Reference document.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by a Transmission Operator or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage.

Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of a Transmission Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with a Transmission Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

If the Transmission Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the TO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

Requirement R3: R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, a Transmission Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the Transmission Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the Transmission Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the Transmission Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach a Transmission Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the Transmission Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below. In the Technical Reference document more figures and explanations of conductor dynamics are provided.

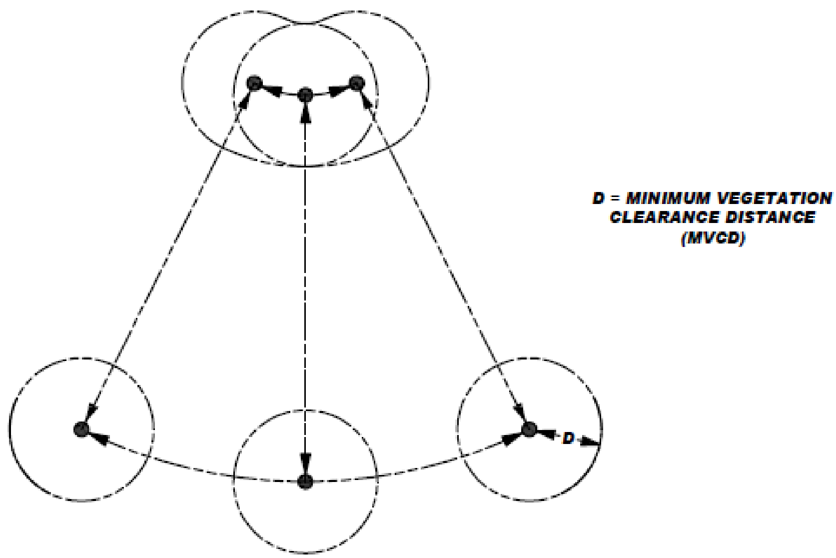


Figure 1

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

Requirement R4:
R4 is a risk-based requirement. It focuses on preventative actions to be taken by the Transmission Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of a Transmission Owner's employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The Transmission Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or other preparatory actions in recognition of the increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some Transmission Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5:
R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the Transmission Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the Transmission Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the Transmission Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the Transmission Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the Transmission Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the Transmission Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.

- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for the location.
- In developing the specific action to mitigate the potential risk to the transmission line the Transmission Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The Transmission Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:
R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections. The provision that Vegetation Inspections can be performed in conjunction with general line inspections facilitates a Transmission Owner's ability to meet this requirement. However, the Transmission Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, based on factors such as anticipated growth rates of the local vegetation, length of the local growing season, limited ROW width, and local rainfall. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The VSLs for Requirement R6 have levels ranked by the failure to inspect a percentage of the applicable lines to be inspected. To calculate the appropriate VSL the Transmission Owner may choose units such as: circuit, pole line, line miles or kilometers, etc.

For example, when a Transmission Owner operates 2,000 miles of applicable transmission lines this Transmission Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

Requirement R7:
R7 is a risk-based requirement. The Transmission Owner is required to complete its an annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a “span-by-span”, or even a “line-by-line” detailed description of all work to be performed. It is only intended to require that the Transmission Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

For example, when a Transmission Owner identifies 1,000 miles of applicable transmission lines to be completed in the Transmission Owner’s annual plan, the Transmission Owner will be responsible completing those identified miles. If a Transmission Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be: 1000 – 100 (deferred miles) = 900 modified annual plan, or 900 / 900 = 100% completed annual miles. If a Transmission Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: 1000 – 875 = 125 miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the Transmission Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the Transmission Owner’s system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the Transmission Owner’s easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the Transmission Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Transmission Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the Transmission Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

FAC-003 — TABLE 2 — Minimum Vegetation Clearance Distances (MVCD)[7]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)	(AC) Maximum System Voltage (kV)[8]	MVCD (feet) Over sea level up to 500 ft	MVCD (feet) Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft
765	800	8.2ft	8.33ft	8.61ft	8.89ft	9.17ft	9.45ft	9.73ft	10.01ft	10.29ft	10.57ft	10.85ft	11.13ft
500	550	5.15ft	5.25ft	5.45ft	5.66ft	5.86ft	6.07ft	6.28ft	6.49ft	6.7ft	6.92ft	7.13ft	7.35ft
345	362	3.19ft	3.26ft	3.39ft	3.53ft	3.67ft	3.82ft	3.97ft	4.12ft	4.27ft	4.43ft	4.58ft	4.74ft
287	302	3.88ft	3.96ft	4.12ft	4.29ft	4.45ft	4.62ft	4.79ft	4.97ft	5.14ft	5.32ft	5.50ft	5.68ft
230	242	3.03ft	3.09ft	3.22ft	3.36ft	3.49ft	3.63ft	3.78ft	3.92ft	4.07ft	4.22ft	4.37ft	4.53ft
161*	169	2.05ft	2.09ft	2.19ft	2.28ft	2.38ft	2.48ft	2.58ft	2.69ft	2.8ft	2.91ft	3.03ft	3.14ft
138*	145	1.74ft	1.78ft	1.86ft	1.94ft	2.03ft	2.12ft	2.21ft	2.3ft	2.4ft	2.49ft	2.59ft	2.7ft
115*	121	1.44ft	1.47ft	1.54ft	1.61ft	1.68ft	1.75ft	1.83ft	1.91ft	1.99ft	2.07ft	2.16ft	2.25ft
88*	100	1.18ft	1.21ft	1.26ft	1.32ft	1.38ft	1.44ft	1.5ft	1.57ft	1.64ft	1.71ft	1.78ft	1.86ft
69*	72	0.84ft	0.86ft	0.90ft	0.94ft	0.99ft	1.03ft	1.08ft	1.13ft	1.18ft	1.23ft	1.28ft	1.34ft

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

[7] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[8] Where applicable lines are operated at nominal voltages other than those listed, The Transmission Owner should use the maximum system voltage to determine the appropriate clearance for that line.

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[7]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)	(AC) Maximum System Voltage (kV)[8]	MVCD meters Over sea level up to 152.4 m	MVCD meters Over 152.4 m up to 304.8 m	MVCD meters Over 304.8 m up to 609.6m	MVCD meters Over 609.6m up to 914.4m	MVCD meters Over 914.4m up to 1219.2m	MVCD meters Over 1219.2m up to 1524m	MVCD meters Over 1524 m up to 1828.8 m	MVCD meters Over 1828.8m up to 2133.6m	MVCD meters Over 2133.6m up to 2438.4m	MVCD meters Over 2438.4m up to 2743.2m	MVCD meters Over 2743.2m up to 3048m	MVCD meters Over 3048m up to 3352.8m
765	800	2.49m	2.54m	2.62m	2.71m	2.80m	2.88m	2.97m	3.05m	3.14m	3.22m	3.31m	3.39m
500	550	1.57m	1.6m	1.66m	1.73m	1.79m	1.85m	1.91m	1.98m	2.04m	2.11m	2.17m	2.24m
345	362	0.97m	0.99m	1.03m	1.08m	1.12m	1.16m	1.21m	1.26m	1.30m	1.35m	1.40m	1.44m
287	302	1.18m	0.88m	1.26m	1.31m	1.36m	1.41m	1.46m	1.51m	1.57m	1.62m	1.68m	1.73m
230	242	0.92m	0.94m	0.98m	1.02m	1.06m	1.11m	1.15m	1.19m	1.24m	1.29m	1.33m	1.38m
161*	169	0.62m	0.64m	0.67m	0.69m	0.73m	0.76m	0.79m	0.82m	0.85m	0.89m	0.92m	0.96m
138*	145	0.53m	0.54m	0.57m	0.59m	0.62m	0.65m	0.67m	0.70m	0.73m	0.76m	0.79m	0.82m
115*	121	0.44m	0.45m	0.47m	0.49m	0.51m	0.53m	0.56m	0.58m	0.61m	0.63m	0.66m	0.69m
88*	100	0.36m	0.37m	0.38m	0.40m	0.42m	0.44m	0.46m	0.48m	0.50m	0.52m	0.54m	0.57m
69*	72	0.26m	0.26m	0.27m	0.29m	0.30m	0.31m	0.33m	0.34m	0.36m	0.37m	0.39m	0.41m

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[7]

For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	**(DC) Nominal Pole to Ground Voltage (kV)**	**(DC) Nominal Pole to Ground Voltage (kV)**	**(DC) Nominal Pole to Ground Voltage (kV)**	**(DC) Nominal Pole to Ground Voltage (kV)**	**(DC) Nominal Pole to Ground Voltage (kV)**	**(DC) Nominal Pole to Ground Voltage (kV)**	**(DC) Nominal Pole to Ground Voltage (kV)**	**(DC) Nominal Pole to Ground Voltage (kV)**	**(DC) Nominal Pole to Ground Voltage (kV)**	**(DC) Nominal Pole to Ground Voltage (kV)**	**(DC) Nominal Pole to Ground Voltage (kV)**	**(DC) Nominal Pole to Ground Voltage (kV)**
	Over sea level up to 500 ft	**Over 500 ft up to 1000 ft**	**Over 1000 ft up to 2000 ft**	**Over 2000 ft up to 3000 ft**	**Over 3000 ft up to 4000 ft**	**Over 4000 ft up to 5000 ft**	**Over 5000 ft up to 6000 ft**	**Over 6000 ft up to 7000 ft**	**Over 7000 ft up to 8000 ft**	**Over 8000 ft up to 9000 ft**	**Over 9000 ft up to 10000 ft**	**Over 10000 ft up to 11000 ft**
	(Over sea level up to 152.4 m)	**(Over 152.4 m up to 304.8 m**	**(Over 304.8 m up to 609.6m)**	**(Over 609.6m up to 914.4m**	**(Over 914.4m up to 1219.2m**	**(Over 1219.2m up to 1524m**	**(Over 1524 m up to 1828.8 m)**	**(Over 1828.8m up to 2133.6m)**	**(Over 2133.6m up to 2438.4m)**	**(Over 2438.4m up to 2743.2m)**	**(Over 2743.2m up to 3048m)**	**(Over 3048m up to 3352.8m)**
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table 7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table 5 would have to be used. Table 5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at 302 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.
The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations.

Comparison of spark-over distances computed using Gallet wet equations vs. IEEE 516-2003 MAID distances

(AC) Nom System Voltage (kV)	(AC) Max System Voltage (kV)	Transient Over-voltage Factor (T)	Clearance (ft.) Gallet (wet) @ Alt. 3000 feet	Table 7 (Table D.5 for feet) IEEE 516-2003 MAID (ft) @ Alt. 3000 feet
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SC approved SAR for initial posting (January 11, 2007).
2. SAR posted for comment (January 15–February 14, 2007).
3. SAR posted for comment (April 10–May 9, 2007).
4. SC authorized moving the SAR forward to standard development (June 27, 2007).
5. First draft of proposed standard posted (October 27, 2008-November 25, 2008)).
6. Second draft of revised standard posted (September 10, 20-October 24, 2009).
7. Third draft of revised standard posted (March 1, 2010-March 31, 2010).
8. ~~Forth~~Fourth draft of revised standard posted (June 17, 2010-July 17, 2010).
9. Fifth draft of revised standard posted (February 18, 2011-February 28, 2011)
10. Sixth draft of revised standard posted (September xx - 2011)

Proposed Action Plan and Description of Current Draft

This is the ~~third~~fourth posting of the proposed revisions to the standard in accordance with Results-Based Criteria and the ~~fifth~~sixth draft overall.

Future Development Plan

Anticipated Actions	Anticipated Date
Recirculation ballot of standards.	~~January~~September 2011
Receive BOT approval	~~February~~November 2011

Effective Dates

~~First~~This standard becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval is required. Where no regulatory approval is required, the standard becomes effective on the first calendar day of the first calendar quarter one year after Board of Trustees adoption.

~~Exceptions:~~Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC ~~transfer path~~Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being ~~subject~~an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to ~~this standard.~~become an element of an IROL or an element of a Major WECC Transfer Path.

2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.

3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.

4. An existing transmission line operated at 200kV or higher ~~that~~which is newly acquired by an asset owner and which was not previously subject to this standard~~,~~ becomes subject to this standard 12 months after the acquisition date~~ of the line.~~.

5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

Version History

Version	Date	Action	Change Tracking
1	TBA	1. Added “Standard Development Roadmap.” 2. Changed “60” to “Sixty” in section A, 5.2. 3. Added “Proposed Effective Date: April 7, 2006” to footer. 4. Added “Draft 3: November 17, 2005” to footer.	01/20/06
1	April 4, 2007	Regulatory Approval — Effective Date	New
2			

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary. ~~*When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.*~~

Right-of-Way (ROW)

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.

The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

Vegetation Inspection

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

~~The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.~~

~~Current definition of Vegetation Inspection: The systematic examination of a transmission corridor to document vegetation conditions.~~

Minimum Vegetation Clearance Distance (MVCD)

The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

When this standard has received ballot approval, the text boxes will be moved to the Guideline and Technical Basis Section.

A. Introduction

1. Title: Transmission Vegetation Management

2. Number: FAC-003-2

3. ~~Objectives~~Purpose: To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.

4. Applicability

4.1. Functional Entities:

4.1.1 Transmission Owners

4.2. Facilities: Defined below (referred to as “applicable lines”), including but not limited to those that cross lands owned by federal[1], state, provincial, public, private, or tribal entities:

4.2.1. ~~Overhead~~Each overhead transmission ~~lines~~line operated at 200kV or higher.

4.2.2. ~~Overhead~~Each overhead transmission ~~lines~~line operated below 200kV ~~having been~~ identified as ~~included in the definition~~an element of an ~~Interconnection Reliability Operating Limit (~~IROL~~)~~ under NERC Standard FAC-014 by the Planning Coordinator.

4.2.3. ~~Overhead~~Each overhead transmission ~~lines~~line operated below 200 kV ~~having been~~ identified as ~~included in the definition~~an element of ~~one of the~~a Major WECC Transfer ~~*Paths*~~Path in the Bulk Electric System by WECC.

4.2.4. ~~This standard applies to~~Each overhead transmission ~~lines~~line

Rationale: The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) NERC has a

~~**Rationale**~~

~~The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) The standard was written for Transmission Owners. Rolling the excluded areas into this standard will bring GO and DP into the standard, even though NERC has an initiative in place to address this bigger registry issue. 4) Specifically addressing the areas where the standard applies or doesn’t makes the standard stronger as it relates to clarity.~~

[1] EPAct 2005 section 1211c: “*Access approvals by Federal agencies*~~”.~~.”

identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

Enforcement: ~~*The reliability obligations of the applicable entities and facilities are contained within the technical requirements of this standard. [Straw proposal]*~~

~~**5. Background:**~~

~~This NERC Vegetation Management Standard ("Standard") uses a defense-in-depth approach to improve the reliability of the electric Transmission System by preventing those vegetation related outages that could lead to Cascading. This Standard is not intended to address non-preventable outages such as those due to vegetation fall-ins or blow-ins from outside the Right-of-Way, vandalism, human activities and acts of nature. Operating experience indicates that trees that have grown out of specification have contributed to Cascading, especially under heavy electrical loading conditions.~~

~~With a defense-in-depth strategy, this Standard utilizes~~The Requirements within a Reliability Standard govern and will be enforced. The Requirements within a Reliability Standard define what an entity must do to be compliant and binds an entity to certain obligations of performance under Section 215 of the Federal Power Act. Compliance will in all cases be measured by determining whether a party met or failed to meet the Reliability Standard Requirement given the specific facts and circumstances of its use, ownership or operation of the bulk power system.

Measures provide guidance on assessing non-compliance with the Requirements. Measures are the evidence that could be presented to demonstrate compliance with a Reliability Standard Requirement and are not intended to contain the quantitative metrics for determining satisfactory performance nor to limit how an entity may demonstrate compliance if valid alternatives to demonstrating compliance are available in a specific case. A Reliability Standard may be enforced in the absence of specified Measures.

Entities must comply with the "Compliance" section in its entirety, including the Administrative Procedure that sets forth, among other things, reporting requirements.

The "Guideline and Technical Basis" section, the Background section and text boxes with "Examples" and "Rationale" are provided for informational purposes. They are designed to convey guidance from NERC's various activities. The "Guideline and Technical Basis" section and text boxes with "Examples" and "Rationale" are not intended to establish new Requirements under NERC's Reliability Standards or to modify the Requirements in any existing NERC Reliability Standard. Implementation of the "Guideline and Technical Basis" section, the Background section and text boxes with "Examples" and "Rationale" is not a substitute for compliance with Requirements in NERC's Reliability Standards."

5. Background:

This standard uses three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

a) Performance-based —— defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome*?

b) Risk-based —— preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system*?

c) Competency-based —— defines a minimum ~~capability~~set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system*?

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard. ~~For this Standard, the requirements have been developed as follows:~~

~~•~~ This standard uses a defense-in-depth approach to improve the reliability of the electric Transmission system by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- ~~•~~ Competency-based: Requirement 3
- ~~•~~ Risk-based: Requirements 4, 5, 6 and 7

~~Thus the various requirements associated with a successful vegetation program could be viewed as using R1, R2 and R3 as first levels of defense; while R4 could be a subsequent or final level of defense. R6 depending on the particular vegetation approach may be either an initial defense barrier or a final defense barrier.~~ R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the ~~Standard~~standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the ~~Standard~~standard the term "public lands" includes municipal lands, village lands, city lands, and a host of other governmental entities.

This ~~Standard~~standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

This ~~Standard~~standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this ~~Standard~~standard is not written to address such isolated situations which have little impact on the overall electric transmission system.

Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of ~~multiple~~consecutive line failures ~~and~~when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) ~~are statistically intermittent.~~ are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this ~~Standard's emphasis is~~standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

B. Requirements and Measures

R1. Each Transmission Owner shall manage vegetation to prevent encroachments ~~of the types shown below,~~ into the ~~Minimum Vegetation Clearance Distance (~~MVCD~~) of any~~ of its applicable line(s) ~~identified as~~which are either an element of an ~~Interconnection Reliability Operating Limit (~~IROL~~) in the planning horizon by the Planning Coordinator;~~, or an element of a Major ~~Western Electricity Coordinating Council (~~WECC~~) transfer path(s);~~ Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions~~.~~ ~~[2]~~ of the types shown below[3] [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage[4],
2. An encroachment due to a fall-in from inside the ~~Right-of-Way (~~ROW~~)~~ that caused a vegetation-related Sustained Outage[5],
3. An encroachment due to the blowing together of applicable

Rationale for R1 and R2:

~~**Rationale**~~

~~The MVCD is a calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method. The types of failure to manage vegetation are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO's vegetation maintenance program since the encroachments listed require different and increasing levels of skills and knowledge and thus constitute a logical progression of how well, or poorly, a TO manages vegetation relative to this Requirement.~~

3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.

4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

~~[2] This requirement does not apply to circumstances that are b[...] this reliability standard, including natural disasters such as ea[...] shear, fresh gale, major storms as defined either by the Trans[...] storms, and floods; human or animal activity such as logging, [...] arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.~~

[3] This requirement does not apply to circumstances that are beyond the control of a Transmission Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

[4] If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

[5] Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

lines and vegetation located inside the ROW that caused a vegetation-related Sustained ~~Outage~~Outage[4],

4. An encroachment due to ~~a grow-in~~vegetation growth into the MVCD that caused a vegetation-related Sustained ~~Outage.~~ Outage[4].

~~[VRF – High] [Time Horizon – Real-time]~~

M1. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

~~If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.~~

~~Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. (R1)~~

R2. Each Transmission Owner shall manage vegetation to prevent encroachments ~~of the types shown below,~~ into the MVCD of ~~any of~~ its applicable line(s) ~~that is~~which are not either an element of an IROL~~;~~, or an element of a Major WECC ~~transfer path~~Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions~~.~~[2] of the types shown below[2] [*Violation Risk Factor: Medium*] [*Time Horizon: Real-time*]:

1. An encroachment into the MVCD as shown in FAC-003-Table 2 ~~as shown in FAC-003-Table 2~~, observed in Real-time, absent a Sustained ~~Outage~~Outage[3],
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained ~~Outage~~Outage[4],
3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained ~~Outage~~Outage[4],
4. An encroachment due to ~~a grow-in~~vegetation growth into the MVCD that caused a vegetation-related Sustained ~~Outage.~~Outage[4]

~~**Rationale**~~

~~The MVCD is a calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method. The types of failure to manage vegetation are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a TO's vegetation maintenance program since the encroachments listed require different and increasing levels of skills and knowledge and thus constitute a logical progression of how well, or poorly, a TO manages vegetation relative to this Requirement.~~

~~*[VRF – Medium] [Time Horizon – Real-time]*~~

M2. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)

~~If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.~~

~~Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. (R2)~~

R3. Each Transmission Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable ~~transmission~~ lines that ~~include(s)~~accounts for the following:

3.1 ~~Accounts for the movement~~Movement of applicable ~~transmission~~ line conductors under their ~~Facility~~ Rating and all Rated Electrical Operating Conditions;

3.2 ~~Accounts for the inter~~Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.

~~*[VRF —*~~*[Violation Risk Factor:* *Lower*] [*Time Horizon*~~—~~*:* *Long Term Planning*~~]~~*]:*

Rationale

The documentation provides a basis for evaluating the competency of the Transmission Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the Transmission Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. See Figure 1 for an illustration of possible conductor locations.

M3. The maintenance strategies or procedures or processes or specifications provided demonstrate that the Transmission Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)

R4. Each Transmission Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable ~~transmission~~ line when the Transmission Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment~~.~~ *[Violation Risk Factor: Medium*] [*Time Horizon: Real-time*].

Rationale

~~To~~This is to ensure expeditious communication between the Transmission Owner and the control center when a critical situation is confirmed.

~~*[VRF — Medium] [Time Horizon — Real-time]*~~

M4. Each Transmission Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)

R5. When a Transmission Owner is constrained from performing vegetation work on an applicable line operating within its Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD ~~of its applicable transmission lines~~ prior to the implementation of the next annual work plan, then the Transmission Owner shall take corrective action to ensure continued vegetation management to prevent encroachments~~.~~ [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*].

Rationale

Legal actions and other events may occur which result in constraints that prevent the Transmission Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the Transmission Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

~~*[VRF – Medium] [Time Horizon – Operations Planning]*~~

M5. Each Transmission Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, ~~and~~or evidence that ~~a~~the line was de-energized. (R5)

R6. Each Transmission Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 calendar months between inspections on the same ROW~~.~~[~~6~~7] [*Violation Risk Factor:*

~~**Rationale**~~

~~Inspections are used by Transmission Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.~~

~~[6] When the Transmission Owner is prevented from performing a V~~
~~due to a natural disaster, the TO is granted a time extension that i~~
~~prevented from performing the Vegetation Inspection.~~

Medium] [*Time Horizon: Operations Planning*].

~~*[VRF – Medium] [Time Horizon – Operations Planning]*~~

M6. Each Transmission Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable ~~transmission~~ lines at least once per calendar year but with no more than 18 calendar months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)

R7. Each Transmission Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not ~~put the transmission system at risk~~allow encroachment of ~~a~~ vegetation ~~encroachment~~into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include~~:~~ [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]:

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of a Transmission Owner[8]
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

~~**Rationale**~~

~~This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. An annual vegetation work plan allows for work to be modified for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that the changes do not violate the encroachment within the MVCD.~~

factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

[7] When the Transmission Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO is granted a time extension that is equivalent to the duration of the time the TO was prevented from performing the Vegetation Inspection.

[8] Circumstances that are beyond the control of a Transmission Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or an applicable regulatory body~~, ice storms, and floods; arboricultural, horticultural or agricultural activities~~.

~~*[VRF – Medium] [Time Horizon – Operations Planning]*~~

M7. Each Transmission Owner has evidence that it completed its annual vegetation work plan~~.~~ for its applicable lines. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (~~including modifications if any~~as finally modified), dated work orders, dated invoices, or dated inspection records. (R7)

C. Compliance

1. Compliance Monitoring Process

1.1 Compliance Enforcement Authority

1.2 Regional Entity Evidence Retention

~~**Compliance Monitoring and Enforcement Processes:**~~

- ~~Compliance Audits~~
- ~~Self-Certifications~~
- ~~Spot Checking~~
- ~~Compliance Violation Investigations~~
- ~~Self-Reporting~~
- ~~Complaints~~
- ~~Periodic Data Submittals~~

~~**Evidence Retention**~~

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Owner retains data or evidence to show compliance with Requirements R1, R2, R3, R5, R6 and R7, Measures M1, M2, M3, M5, M6 and M7 for three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner retains data or evidence to show compliance with Requirement R4, Measure M4 for most recent 12 months of operator logs or most recent 3 months of voice recordings or transcripts of voice recordings, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3 Compliance Monitoring and Enforcement Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaint

Periodic Data Submittal

~~1.3~~1.4 Additional Compliance Information

Periodic Data Submittal: The Transmission Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable ~~transmission lines~~lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the Transmission Owner to have been caused by vegetation, except as excluded in footnote 2, ~~which includes~~and including as a minimum~~,~~ the following:

- The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained Outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.

A Sustained Outage is to be categorized as one of the following:

- Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable ~~transmission~~ lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable ~~transmission~~ lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW;
- Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable ~~transmission~~ lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable ~~transmission~~ lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW;
- Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable ~~transmission~~ lines from outside the ROW;
- Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable ~~transmission~~ lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

- Category 4B — Blowing together: Sustained Outages caused by vegetation and applicable ~~transmission~~ lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW.

The Regional Entity will report the outage information provided by Transmission Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.

~~Time Horizons, Violation Risk Factors, and Violation Severity Levels~~

~~Table 1~~

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Level			
			Lower	Moderate	High	Severe
R1	Real-time	High	~~The~~The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.	~~The~~The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage.	~~The~~The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.	~~The~~The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD due to a grow-in that caused a vegetation-related Sustained Outage.
R2	Real-time	Medium	~~The~~The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD observed in Real-time, absent a Sustained Outage.	~~The~~The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage.	~~The~~The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage.	~~The~~The Transmission Owner failed to manage vegetation in a manner such that the Transmission Owner had an encroachment into the MVCD due to a grow-in that caused a vegetation-related Sustained Outage.
R3	Long-Term Planning	Lower		The Transmission Owner has maintenance strategies or documented procedures or processes or specifications but has not accounted for the	The Transmission Owner has maintenance strategies or documented procedures or processes or specifications but has not accounted for the	The Transmission Owner does not have any maintenance strategies or documented procedures or processes or specifications used to prevent

				inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency, for the Transmission Owner's applicable lines. (Requirement R3, Part 3.2)	movement of transmission line conductors under their Rating and all Rated Electrical Operating Conditions, for the Transmission Owner's applicable lines. Requirement R3, Part 3.1)	the encroachment of vegetation into the MVCD, for the Transmission Owner's applicable lines.
R4	Real-time	Medium			The Transmission Owner experienced a confirmed vegetation threat and notified the control center holding switching authority for that ~~transmission~~applicable line, but there was intentional delay in that notification.	The Transmission Owner experienced a confirmed vegetation threat and did not notify the control center holding switching authority for that ~~transmission~~applicable line.
R5	Operations Planning	Medium				The Transmission Owner did not take corrective action when it was constrained from performing planned vegetation work where ~~a transmission~~an applicable line was put at potential risk.
R6	Operations Planning	Medium	The Transmission Owner failed to inspect 5% or less of its applicable ~~transmission~~ lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.)	The Transmission Owner failed to inspect more than 5% up to and including 10% of its applicable ~~transmission~~ lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The Transmission Owner failed to inspect more than 10% up to and including 15% of its applicable ~~transmission~~ lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).	The Transmission Owner failed to inspect more than 15% of its applicable ~~transmission~~ lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.).
R7	Operations Planning	Medium	The Transmission Owner failed to complete ~~up to~~ 5% or less of its annual vegetation work plan	The Transmission Owner failed to complete more than 5% and up to and including 10% of its annual vegetation	The Transmission Owner failed to complete more than 10% and up to and including 15% of its annual vegetation work plan	The Transmission Owner failed to complete more than 15% of its annual vegetation work plan ~~(including modifications if~~

			~~(including modifications if any~~for its applicable lines (as finally modified).	work plan ~~(including modifications if any~~for its applicable lines (as finally modified).	~~(including modifications if any~~for its applicable lines (as finally modified).	~~any~~for its applicable lines (as finally modified).

~~Variances~~

D. Regional Differences

None.

~~D.~~E. Interpretations

None.

F. Associated Documents

Guideline and Technical Basis (attached).

Guideline and Technical Basis

Effective dates:

The first two sentences of the Effective Dates section is standard language used in most NERC standards to cover the general effective date and is sufficient to cover the vast majority of situations. Five special cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the standard.

Case 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effect for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on January 1 of the PY specified with an allowance of at least 12 months for the Transmission Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.

Date that Planning Study is completed	PY the line will become an IROL element	Date 1	Date 2	Effective Date The latter of Date 1 or Date 2
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

Case 2 is needed because a line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

Case 3 is needed because a line operating at 200 kV or above that once was designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.

Case 4 is needed because an existing line that is to be operated at 200 kV or above can be acquired by a Transmission Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the Transmission Owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network which will thereafter make the line subject to the standard.

Case 5 is needed because an existing line that is operated below 200 kV can be acquired by a Transmission Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the Transmission owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network. In this special case the line upon acquisition was designated as an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC Transfer Path.

Defined Terms:

Explanation for revising the definition of ROW:

The current NERC glossary definition of Right of Way has been modified to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of "right of way" in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included in the revised definition to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

Explanation for revising the definition of Vegetation Inspections:

The current glossary definition of this NERC term is being modified to allow both maintenance inspections and vegetation inspections to be performed concurrently. This allows potential efficiencies, especially for those lines with minimal vegetation and/or slow vegetation growth rates.

Explanation of the definition of the MVCD:

The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method of calculating a flash over distance that has been used in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figure 1. Table 2 below provides MVCD values for various voltages and altitudes. Details of the equations and an example calculation are provided in Appendix 1 of the Technical Reference Document.

Requirements R1 and R2:

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the ~~prevention of~~management of vegetation such that there are no vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each Transmission Owner to manage vegetation to prevent encroachment within the ~~Minimum Vegetation Clearance Distance (“~~MVCD~~”)~~ of transmission lines. R1 is applicable to lines “that are identified as an element of an ~~Interconnection Reliability Operating Limit (IROL) or Major Western Electricity Coordinating Council (WECC) transfer path (operating within Rating and Rated Electrical Operating Conditions) to avoid a Sustained Outage”. R2 applies~~IROL or Major WECC Transfer Path. R2 is applicable to all other ~~applicable~~ lines that are not ~~an element~~elements of ~~an IROL or~~IROLs, and not elements of Major WECC Transfer ~~Path~~Paths.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an ~~encroachment into the MVCD~~applicable line that is an element of an IROL or a Major WECC Transfer Path ~~transmission line~~ is a greater risk to the interconnected electric transmission system~~.~~ than applicable lines that are not elements of IROLs or Major WECC Transfer Paths. Applicable lines that are not ~~an element~~elements of ~~an IROL~~IROLs or Major WECC Transfer ~~Path are required to be clear of~~Paths do require effective vegetation management, but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

~~These requirements (~~Requirements R1 and R2~~)~~ state that if inadequate vegetation ~~encroaches~~management allows vegetation to encroach within the ~~distances~~ MVCD distance as shown in Table ~~1 in Appendix 1 of this supplemental Transmission Vegetation Management Standard FAC-003~~ 2 ~~Technical Reference document~~, it is ~~in~~a violation of the standard. Table 2 ~~tabulates~~distances are the

~~distances necessary to~~minimum clearances that will prevent spark-over based on the Gallet equations as described more fully in ~~Appendix 1 below.~~ the Technical Reference document.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur~~.~~ solely due to that condition. For example, emergency actions taken by a Transmission Operator or Reliability Coordinator to protect an Interconnection may cause ~~the transmission line to sag more~~excessive sagging and ~~come closer to vegetation, potentially causing~~ an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not ~~a violation~~violations of ~~these requirements~~this standard.

Evidence of ~~violation of Requirement R1 and R2~~failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of ~~applicable~~the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. ~~If an investigation of~~ Faults which do not cause a ~~Fault by a Transmission Owner confirms that a~~Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD ~~occurred, then it shall be~~are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs ~~were defined~~for R1 and R2 are structured such that they directly correlate to the severity of a failure of a Transmission Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the ~~goal~~objective of "preventing ~~a Sustained Outage~~the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with a Transmission Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example~~, a limb~~ initial investigations and corrective actions may ~~only partially break and intermittently contact a~~not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor~~.~~ temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the ~~Standard~~standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

If the Transmission Owner has applicable lines operated at nominal voltage levels not listed in Table 2, then the TO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

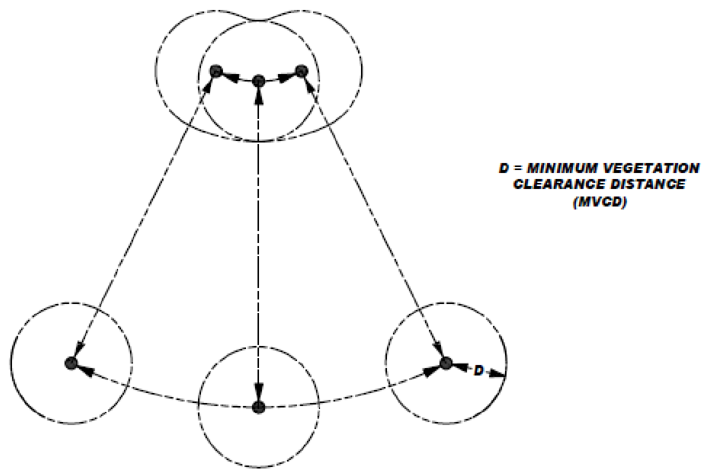
Requirement R3:
~~Requirement~~ R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, a Transmission Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the Transmission Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the ~~Transmission System.~~transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources, and the competency of the Transmission Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the Transmission Owner must be able to ~~state what~~show the documentation of its approach ~~is~~ and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach a Transmission Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the Transmission Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing ~~as a~~in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figure 1 below. In the Technical Reference document more figures and explanations of conductor dynamics are provided.


D
D = MINIMUM VEGETATION
CLEARANCE DISTANCE
(MVCD)

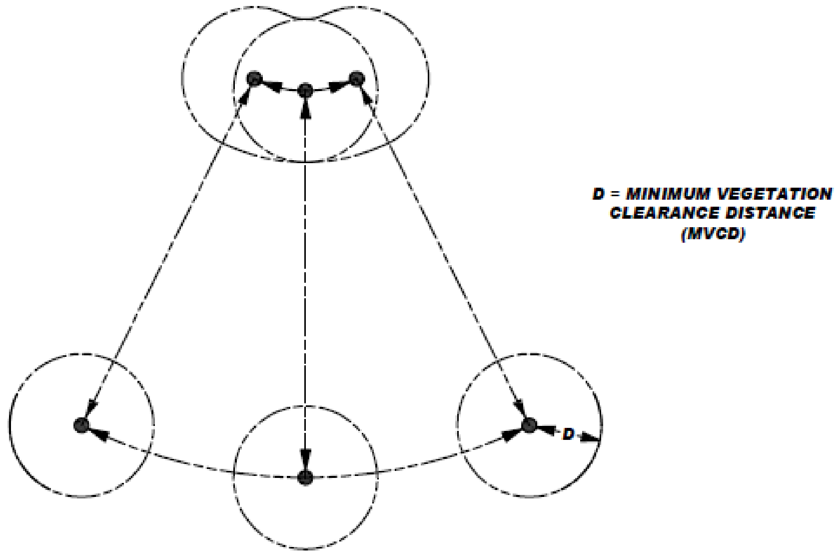


Figure 1

~~Cross~~
A cross-section view of a single conductor at a given point along the span ~~showing~~is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

Requirement R4:
R4 is a risk-based requirement. It focuses on preventative actions to be taken by the Transmission Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of a Transmission Owner's employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The Transmission Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until or as the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or ~~positioning the system~~other preparatory actions in recognition of the ~~increasing~~increased risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some Transmission Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5:
R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the Transmission Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the Transmission Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the Transmission Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the Transmission Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the Transmission Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the Transmission Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.

- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for ~~each~~the location.
- In developing the specific action to mitigate the potential risk to the transmission line the Transmission Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The Transmission Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6:
R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections~~ that fits general industry practice. In addition, the fact~~. The provision that Vegetation Inspections can be performed in conjunction with general line inspections~~ further~~ facilitates a Transmission Owner's ability to meet this requirement. However, the Transmission Owner may determine that more frequent vegetation specific inspections are needed to maintain reliability levels, ~~dependent upon such~~based on factors such as anticipated growth rates of the local vegetation, length of the local growing season~~ for the geographical area~~, limited ROW width, and local rainfall~~ amounts~~. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

The ~~VSL~~VSLs for Requirement R6 ~~has VSL categories~~have levels ranked by the failure to inspect a percentage of the ~~required ROW inspections completed.~~applicable lines to be inspected. To calculate the ~~percentage of inspection completion, ~~appropriate VSL the Transmission Owner may choose units such as: circuit, pole line, line miles or kilometers, ~~circuit miles or kilometers, pole line miles, ROW miles, ~~etc.

For example, when a Transmission Owner operates 2,000 miles of ~~230 kV~~applicable transmission lines this Transmission Owner will be responsible for inspecting all the 2,000 miles of ~~230 kV transmission ~~lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. The "Low VSL" for R6 would apply in this example.

Requirement R7:

R7 is a risk-based requirement. The Transmission Owner is required to ~~implement~~complete its an annual work plan for vegetation management to accomplish the purpose of this standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual work plan requirement is not intended to necessarily require a "span-by-span", or even a "line-by-line" detailed description of all work to be performed. It is only intended to require that the Transmission Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

For example, when a Transmission Owner identifies 1,000 miles of applicable transmission lines to be completed in the Transmission Owner's annual plan, the Transmission Owner will be responsible completing those identified miles. If a Transmission Owner makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be: 1000 – 100 (deferred miles) = 900 modified annual plan, or 900 / 900 = 100% completed annual miles. If a Transmission Owner only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: 1000 – 875 = 125 miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the Transmission Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance. This situation may also include complying with mutual assistance agreements by moving resources off the Transmission Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan~~. Modifications to the annual work plan must always ensure the reliability of the electric Transmission system.~~ provided that they do not put the transmission system at risk of a vegetation encroachment.

In general, the vegetation management maintenance approach should use the full extent of the Transmission Owner's easement, fee simple and other legal rights allowed. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management because in the long term~~ because~~ it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the Transmission Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Transmission Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the Transmission Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs, and walk-through reports.

FAC-003 — Table 2 — Minimum Vegetation Clearance Distances (MVCD)[9]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage ~~(kV)~~(KV)	(AC) Maximum System Voltage (kV)[10]	MVCD (feet ~~(meters)~~) ~~sea level~~	MVCD (feet)	MVCD feet	MVCD feet ~~(meters) 3,000ft (914.4m)~~	MVCD feet ~~(meters) 4,000ft (1219.2m)~~	MVCD feet ~~(meters) 5,000ft (1524m)~~	MVCD feet ~~(meters) 6,000ft (1828.8m)~~	MVCD feet ~~(meters) 7,000ft (2133.6m)~~	MVCD feet ~~(meters) 8,000ft (2438.4m)~~	MVCD feet ~~(meters) 9,000ft (2743.2m)~~	MVCD feet ~~(meters) 10,000ft (3048m)~~	MVCD feet ~~(meters) 11,000ft (3352.8m)~~
		Over sea level up to 500 ft	Over 500 ft up to 1000 ft	Over 1000 ft up to 2000 ft	Over 2000 ft up to 3000 ft	Over 3000 ft up to 4000 ft	Over 4000 ft up to 5000 ft	Over 5000 ft up to 6000 ft	Over 6000 ft up to 7000 ft	Over 7000 ft up to 8000 ft	Over 8000 ft up to 9000 ft	Over 9000 ft up to 10000 ft	Over 10000 ft up to 11000 ft
765	800	8.~~06ft (2.46m)~~ 2ft	8.33ft	8.61ft	8.89ft ~~(2.71m)~~	9.17ft ~~(2.80m)~~	9.45ft ~~(2.88m)~~	9.73ft ~~(2.97m)~~	10.01ft ~~(3.05m)~~	10.29ft ~~(3.14m)~~	10.57ft ~~(3.22m)~~	10.85ft ~~(3.31m)~~	11.13ft ~~(3.39m)~~
500	550	5.~~06ft (1.54m)~~ 15ft	5.25ft	5.45ft	5.66ft ~~(1.73m)~~	5.86ft ~~(1.79m)~~	6.07ft ~~(1.85m)~~	6.28ft ~~(1.91m)~~	6.49ft ~~(1.98m)~~	6.7ft ~~(2.04m)~~	6.92ft ~~(2.11m)~~	7.13ft ~~(2.17m)~~	7.35ft ~~(2.24m)~~
345	362	3.~~12ft (0.95m)~~ 19ft	3.26ft	3.39ft	3.53ft ~~(1.08m)~~	3.67ft ~~(1.12m)~~	3.82ft ~~(1.16m)~~	3.97ft ~~(1.21m)~~	4.12ft ~~(1.26m)~~	4.27ft ~~(1.30m)~~	4.43ft ~~(1.35m)~~	4.58ft ~~(1.40m)~~	4.74ft ~~(1.44m)~~
287	302	3.88ft	3.96ft	4.12ft	4.29ft	4.45ft	4.62ft	4.79ft	4.97ft	5.14ft	5.32ft	5.50ft	5.68ft
230	242	~~2.97ft (0.91m)~~ 3.03ft	3.09ft	3.22ft	3.36ft ~~(1.02m)~~	3.49ft ~~(1.06m)~~	3.63ft ~~(1.11m)~~	3.78ft ~~(1.15m)~~	3.92ft ~~(1.19m)~~	4.07ft ~~(1.24m)~~	4.22ft ~~(1.29m)~~	4.37ft ~~(1.33m)~~	4.53ft ~~(1.38m)~~
161*	169	~~2ft (0.61m)~~ 2.05ft	2.09ft	2.19ft	2.28ft ~~(0.69m)~~	2.38ft ~~(0.73m)~~	2.48ft ~~(0.76m)~~	2.58ft ~~(0.79m)~~	2.69ft ~~(0.82m)~~	2.8ft ~~(0.85m)~~	2.91ft ~~(0.89m)~~	3.03ft ~~(0.92m)~~	3.14ft ~~(0.96m)~~

[9] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[10] Where applicable lines are operated at nominal voltages other than those listed, The Transmission Owner should use the maximum system voltage to determine the appropriate clearance for that line.

138*	145	1.~~7ft (0.52m)~~ 74ft	1.78ft	1.86ft	1.94ft ~~(0.59m)~~	2.03ft ~~(0.62m)~~	2.12ft ~~(0.65m)~~	2.21ft ~~(0.67m)~~	2.3ft ~~(0.70m)~~	2.4ft ~~(0.73m)~~	2.49ft ~~(0.76m)~~	2.59ft ~~(0.79m)~~	2.7ft ~~(0.82m)~~
115*	121	1.~~41ft (0.43m)~~ 44ft	1.47ft	1.54ft	1.61ft ~~(0.49m)~~	1.68ft ~~(0.51m)~~	1.75ft ~~(0.53m)~~	1.83ft ~~(0.56m)~~	1.91ft ~~(0.58m)~~	1.99ft ~~(0.61m)~~	2.07ft ~~(0.63m)~~	2.16ft ~~(0.66m)~~	2.25ft ~~(0.69m)~~
88*	100	1.~~15ft (0.35m)~~ 18ft	1.21ft	1.26ft	1.32ft ~~(0.40m)~~	1.38ft ~~(0.42m)~~	1.44ft ~~(0.44m)~~	1.5ft ~~(0.46m)~~	1.57ft ~~(0.48m)~~	1.64ft ~~(0.50m)~~	1.71ft ~~(0.52m)~~	1.78ft ~~(0.54m)~~	1.86ft ~~(0.57m)~~
69*	72	0.~~82ft (0.25m)~~ 84ft	0.86ft	0.90ft	0.94ft ~~(0.29m)~~	0.99ft ~~(0.30m)~~	1.03ft ~~(0.31m)~~	1.08ft ~~(0.33m)~~	1.13ft ~~(0.34m)~~	1.18ft ~~(0.36m)~~	1.23ft ~~(0.37m)~~	1.28ft ~~(0.39m)~~	1.34ft ~~(0.41m)~~

* ~~*~~ Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[7]
For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)	(AC) Maximum System Voltage (kV)[8]	MVCD meters Over sea level up to 152.4 m	MVCD meters Over 152.4 m up to 304.8 m	MVCD meters Over 304.8 m up to 609.6m	MVCD meters Over 609.6m up to 914.4m	MVCD meters Over 914.4m up to 1219.2m	MVCD meters Over 1219.2m up to 1524m	MVCD meters Over 1524 m up to 1828.8 m	MVCD meters Over 1828.8m up to 2133.6m	MVCD meters Over 2133.6m up to 2438.4m	MVCD meters Over 2438.4m up to 2743.2m	MVCD meters Over 2743.2m up to 3048m	MVCD meters Over 3048m up to 3352.8m
765	800	2.49m	2.54m	2.62m	2.71m	2.80m	2.88m	2.97m	3.05m	3.14m	3.22m	3.31m	3.39m
500	550	1.57m	1.6m	1.66m	1.73m	1.79m	1.85m	1.91m	1.98m	2.04m	2.11m	2.17m	2.24m
345	362	0.97m	0.99m	1.03m	1.08m	1.12m	1.16m	1.21m	1.26m	1.30m	1.35m	1.40m	1.44m
287	302	1.18m	0.88m	1.26m	1.31m	1.36m	1.41m	1.46m	1.51m	1.57m	1.62m	1.68m	1.73m
230	242	0.92m	0.94m	0.98m	1.02m	1.06m	1.11m	1.15m	1.19m	1.24m	1.29m	1.33m	1.38m
161*	169	0.62m	0.64m	0.67m	0.69m	0.73m	0.76m	0.79m	0.82m	0.85m	0.89m	0.92m	0.96m

138*	145	0.53m	0.54m	0.57m	0.59m	0.62m	0.65m	0.67m	0.70m	0.73m	0.76m	0.79m	0.82m
115*	121	0.44m	0.45m	0.47m	0.49m	0.51m	0.53m	0.56m	0.58m	0.61m	0.63m	0.66m	0.69m
88*	100	0.36m	0.37m	0.38m	0.40m	0.42m	0.44m	0.46m	0.48m	0.50m	0.52m	0.54m	0.57m
69*	72	0.26m	0.26m	0.27m	0.29m	0.30m	0.31m	0.33m	0.34m	0.36m	0.37m	0.39m	0.41m

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above~~).~~

~~Table 2 (cont.) — Minimum Vegetation Clearance Distances (MVCD)~~)

TABLE 2 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[7]

For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	- ~~MVCD feet (meters)~~ ~~sea level~~ -(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV)	- ~~MVCD feet (meters) 3,000ft (914.4m) Alt.~~ -(DC) Nominal Pole to Ground Voltage (kV)	- ~~MVCD feet (meters) 4,000ft (1219.2m) Alt.~~ -(DC) Nominal Pole to Ground Voltage (kV)	- ~~MVCD feet (meters) 5,000ft (1524m) Alt.~~ -(DC) Nominal Pole to Ground Voltage (kV)	- ~~MVCD feet (meters) 6,000ft (1828.8m) Alt.~~(DC) Nominal Pole to Ground Voltage (kV)	~~MVCD feet (meters) 7,000ft (2133.6m) Alt.~~(DC) Nominal Pole to Ground Voltage (kV)	~~MVCD feet (meters) (8,000ft (2438.4m) Alt.~~ (DC) Nominal Pole to Ground Voltage (kV)	~~MVCD feet (meters) 9,000ft (2743.2 m) Alt.~~ (DC) Nominal Pole to Ground Voltage (kV)	~~MVCD feet (meters) 10,000ft (3048m) Alt.~~ (DC) Nominal Pole to Ground Voltage (kV)	~~MVCD feet (meters) 11,000ft (3352.8 m) Alt.~~(DC) Nominal Pole to Ground Voltage (kV)
	Over sea level up to 500 ft	Over 500 ft up to 1000 ft	Over 1000 ft up to 2000 ft	Over 2000 ft up to 3000 ft	Over 3000 ft up to 4000 ft	Over 4000 ft up to 5000 ft	Over 5000 ft up to 6000 ft	Over 6000 ft up to 7000 ft	Over 7000 ft up to 8000 ft	Over 8000 ft up to 9000 ft	Over 9000 ft up to 10000 ft	Over 10000 ft up to 11000 ft
	(Over sea level up to 152.4 m)	(Over 152.4 m up to 304.8 m	(Over 304.8 m up to 609.6m)	(Over 609.6m up to 914.4m	(Over 914.4m up to 1219.2m	(Over 1219.2m up to 1524m	(Over 1524 m up to 1828.8 m)	(Over 1828.8m up to 2133.6m)	(Over 2133.6m up to 2438.4m)	(Over 2438.4m up to 2743.2m)	(Over 2743.2m up to 3048m)	(Over 3048m up to 3352.8m)

±750	~~13.92ft~~14.12ft (4.~~24m~~30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.~~9ft~~91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.~~07ft~~23ft (3.~~07m~~12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	~~(~~13.54ft (4.13m)
±500	~~7.89ft~~ 8.03ft (2.~~40m~~45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	~~4.78ft~~ 6.07ft (1.~~46m~~85m)	6.18ft (1.88m)	6.41ft (1.95m)	~~5.35ft (1.63m)~~6.63ft (2.02m)	~~5.55ft (1.69m)~~6.86ft (2.09m)	~~5.75ft (1.75m)~~7.09ft (2.16m)	~~5.95ft (1.81m)~~7.33ft (2.23m)	~~6.15ft (1.87m)~~7.56ft (2.30m)	~~6.36ft (1.94m)~~7.80ft (2.38m)	~~6.57ft~~ 8.03ft (2.~~00m~~45m)	~~6.77ft~~ 8.27ft (2.~~06m~~52m)	~~6.98ft~~ 8.51ft (2.~~13m~~59m)
±250	3.~~43ft~~ 50ft (1.~~05m~~07m)	3.57ft (1.09m)	3.72ft (1.13m)	~~4.02ft~~3.87ft (1.~~23m~~18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	~~5ft~~ 5.00ft (1.52m)	5.17ft (1.58m)

Notes:

The SDT determined that the use of IEEE 516-2003 in version 1 of FAC-003 was a misapplication. The SDT consulted specialists who advised that the Gallet Equation would be a technically justified method. The explanation of why the Gallet approach is more appropriate is explained in the paragraphs below.

The drafting team sought a method of establishing minimum clearance distances that uses realistic weather conditions and realistic maximum transient over-voltages factors for in-service transmission lines.

The SDT considered several factors when looking at changes to the minimum vegetation to conductor distances in FAC-003-1:

- avoid the problem associated with referring to tables in another standard (IEEE-516-2003)
- transmission lines operate in non-laboratory environments (wet conditions)
- transient over-voltage factors are lower for in-service transmission lines than for inadvertently re-energized transmission lines with trapped charges.

FAC-003-1 uses the minimum air insulation distance (MAID) without tools formula provided in IEEE 516-2003 to determine the minimum distance between a transmission line conductor and vegetation. The equations and methods provided in IEEE 516 were developed by an IEEE Task Force in 1968 from test data provided by thirteen independent laboratories. The distances provided in IEEE 516 Tables 5 and 7 are based on the withstand voltage of a dry rod-rod air gap, or in other words, dry laboratory conditions. Consequently, the validity of using these distances in an outside environment application has been questioned.

FAC-003-01 allowed Transmission Owners to use either Table 5 or Table 7 to establish the minimum clearance distances. Table ~~5~~7 could be used if the Transmission Owner knew the maximum transient over-voltage factor for its system. Otherwise, Table ~~7~~5 would have to be used. Table ~~7~~5 represented minimum air insulation distances under the worst possible case for transient over-voltage factors. These worst case transient over-voltage factors were as follows: 3.5 for voltages up to 362 kV phase to phase; 3.0 for 500 - 550 kV phase to phase; and 2.5 for 765 to 800 kV phase to phase. These worst case over-voltage factors were also a cause for concern in this particular application of the distances.

In general, the worst case transient over-voltages occur on a transmission line that is inadvertently re-energized immediately after the line is de-energized and a trapped charge is still present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to spark-over from the line conductor to nearby vegetation. Thus, the worst case transient overvoltage assumptions are not appropriate for this application. Rather, the appropriate over voltage values are those that occur only while the line is energized.

Typical values of transient over-voltages of in-service lines, as such, are not readily available in the literature because they are negligible compared with the maximums. A conservative value for the maximum transient over-voltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 per unit. This value is a conservative estimate of the transient over-voltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without pre-insertion devices (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. Maximum System Voltage of 362 kV), the maximum transient over-voltage of an in-service ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 per unit or less.

Even though these transient over-voltages will not be experienced at locations remote from the bus at which they are created, in order to be conservative, it is assumed that all nearby ac lines are subjected to this same level of over-voltage. Thus, a maximum transient over-voltage factor of 2.0 per unit for transmission lines operated at ~~242~~302 kV and below is considered to be a realistic maximum in this application. Likewise, for ac transmission lines operated at Maximum System Voltages of 362 kV and above a transient over-voltage factor of 1.4 per unit is considered a realistic maximum.

The Gallet Equations are an accepted method for insulation coordination in tower design. These equations are used for computing the required strike distances for proper transmission line insulation coordination. They were developed for both wet and dry applications and can be used with any value of transient over-voltage factor. The Gallet Equation also can take into account various air gap geometries. This approach was used to design the first 500 kV and 765 kV lines in North America~~ [1].~~.

If one compares the MAID using the IEEE 516-2003 Table 7 (table D.5 for English values) with the critical spark-over distances computed using the Gallet wet equations, for each of the nominal voltage classes and identical transient over-voltage factors, the Gallet equations yield a more conservative (larger) minimum distance value.

Distances calculated from either the IEEE 516 (dry) formulas or the Gallet “wet” formulas are not vastly different when the same transient overvoltage factors are used; the “wet” equations will consistently produce slightly larger distances than the IEEE 516 equations when the same transient overvoltage is used. While the IEEE 516 equations were only developed for dry conditions the Gallet equations have provisions to calculate spark-over distances for both wet and dry conditions.

While EPRI is currently trying to establish empirical data for spark-over distances to live vegetation, there are no spark-over formulas currently derived expressly for vegetation to conductor minimum distances. Therefore the SDT chose a proven method that has been used in other EHV applications. The Gallet equations relevance to wet conditions and the selection of a Transient Overvoltage Factor that is consistent with the absence of trapped charges on an in-service transmission line make this methodology a better choice.
The following table is an example of the comparison of distances derived from IEEE 516 and the Gallet equations ~~using various transient overvoltage values~~.

Comparison of spark-over distances computed using Gallet wet equations vs. IEEE 516-2003 MAID distances

~~**using various transient over-voltage factors**~~

(AC) ~~Nom System Voltage (kV)~~	(AC) ~~Max System Voltage (kV)~~	Transient ~~Over-voltage Factor (T)~~	Clearance (ft.) ~~Gallet (wet) @ Alt. 3000 feet~~	Table 7 (Table D.5 for feet) IEEE 516-2003 ~~MAID (ft) @ Alt. 3000 feet~~
-	-	-	-	-
~~765~~	~~800~~	~~1.4~~	~~8.89~~	~~8.65~~
~~500~~	~~550~~	~~1.4~~	~~5.65~~	~~4.92~~
~~345~~	~~362~~	~~1.4~~	~~3.52~~	~~3.13~~
~~230~~	~~242~~	~~2.0~~	~~3.35~~	~~2.8~~
~~115~~	~~121~~	~~2.0~~	~~1.6~~	~~1.4~~

- ~~(AC)~~ Nom System Voltage (kV)	- ~~(AC)~~ Max System Voltage (kV)	- ~~Transient~~ Over-voltage Factor (T)	- ~~Clearance (ft.)~~ Gallet (wet) @ Alt. 3000 feet	~~Table 5 (historical maximums) IEEE 516~~ MAID (ft) @ Alt. 3000 feet
765	800	2.0	14.36	13.95
500	550	2.4	11.0	10.07
345	362	3.0	8.55	7.47
230	242	3.0	5.28	4.2
115	121	3.0	2.46	2.1

- ~~(AC)~~ ~~Nom System~~ ~~Voltage (kV)~~	- ~~(AC)~~ ~~Max System~~ ~~Voltage (kV)~~	- ~~Transient~~ ~~Over-voltage~~ ~~Factor (T)~~	- ~~Clearance (ft.)~~ ~~Gallet (wet)~~ ~~@ Alt. 3000 feet~~	~~Table 7~~ ~~IEEE 516~~ ~~MAID (ft)~~ ~~@ Alt. 3000 feet~~
-	-	-	-	-
~~765~~	~~800~~	~~2.5~~	~~20.25~~	~~20.4~~
~~500~~	~~550~~	~~3.0~~	~~15.02~~	~~14.7~~
~~345~~	~~362~~	~~3.5~~	~~10.42~~	~~9.44~~
~~230~~	~~242~~	~~3.5~~	~~6.32~~	~~5.14~~
~~115~~	~~121~~	~~3.5~~	~~2.90~~	~~2.45~~

Implementation Plan

FAC-003-2

Prerequisite Approvals

There are no other Reliability Standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this standard can be implemented.

FAC-003-2 – Vegetation Management

Revision to Sections of Approved Standards and Definitions

There are no proposed revisions to requirements in other already approved standards. There are two revised definitions in the proposed standard. FAC-003-1 will be retired when FAC-003-2 becomes effective.

Compliance with Standard

The standard applies to Transmission Owners.

Effective Date

The effective date is the date entities are expected to meet the performance identified in this standard. The effective date allows entities time to make revisions to their existing transmission vegetation management programs to comply with the new requirements.

This standard becomes effective on the first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval is required. Where no regulatory approval is required, the standard becomes effective on the first calendar day of the first calendar quarter one year after Board of Trustees adoption.

Effective dates for individual lines when they undergo specific transition cases:

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC transfer Path.
2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.

3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.
4. An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard, becomes subject to this standard 12 months after the acquisition date.
5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

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Effective dates for individual lines when they undergo specific transition cases:
~~Exceptions:~~

1. A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC transfer ~~path~~Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC transfer Path~~subject to this standard~~.

2. A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.

~~1.~~3. A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date.

4. An existing transmission line operated at 200kV or higher ~~that~~which is newly acquired by an asset owner and which was not previously subject to this standard, becomes subject to this standard 12 months after the acquisition date~~of the line.~~

~~2.~~5. An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Transmission Vegetation Management

Standard FAC-003-2 Technical Reference

Prepared by the

North American Electric Reliability Corporation

Vegetation Management Standard Drafting Team for NERC Project 2007-07

September 30, 2011

RELIABILITY | ACCOUNTABILITY



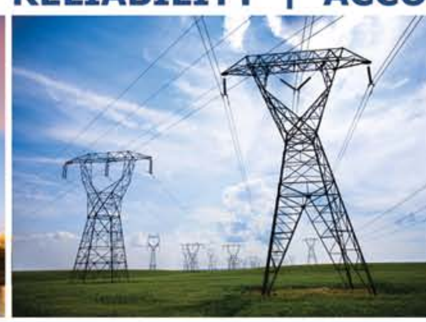


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Table of Contents

Disclaimer

This supporting document is supplemental to the reliability standard FAC-003-2 — Transmission Vegetation Management and does not contain mandatory requirements subject to compliance review. Throughout this document, for ready reference, there are “copies” in italic font of the wording in the Standard. Any “copy” of any part of the Standard in this document should be cross checked to the Standard and if any difference exists, then the Standard’s exact wording should be considered the intended wording for this document.

Introduction

This document is intended to provide supplemental information and guidance for complying with the requirements of Reliability Standard FAC-003-2.

The purpose of the Standard is to improve the reliability of the electric transmission system by preventing those vegetation related outages that could lead to Cascading.

Compliance with the Standard is mandatory and enforceable.

Special Note: The Application of the Results-Based Approach to FAC-003-2

In its three-year assessment as the ERO, NERC acknowledged stakeholder comments and committed to:

i) addressing quality issues to ensure each reliability standard has a clear statement of purpose, and has outcome-focused requirements that are clear and measurable; and
ii) eliminating requirements that do not have an impact on bulk power system reliability.

In 2010, the Standards Committee approved a recommendation to use Project 2007-07 Vegetation Management as a first proof of concept for developing results-based standards.

This standard is not intended to address outages such as those due to vegetation fall-ins or blow-ins from outside the Right-of-Way, vandalism, human activities or acts of nature. Operating experience indicates that trees that have grown out of specification have contributed to Cascading, especially under heavy electrical loading conditions.

This standard utilizes three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

a) Performance-based — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome*?
b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome *<u>that reduces a stated risk to the reliability of the bulk power system</u>*?
c) Competency-based — defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability <u>of the bulk power system</u>*?

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

This NERC Vegetation Management Standard (“standard”) uses a defense-in-depth approach to improve the reliability of the electric Transmission System by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term “public lands” includes municipal lands, village lands, city lands, and a host of other governmental entities.

The standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

The standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.
Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

The drafting team reviewed and edited version 1 of FAC-003-1 to remove prescriptive and administrative language in order to distill the technical requirements down to their essential reliability content. Explanatory text is offered within two special sections, <u>Background</u> and <u>Guideline and Technical Basis</u>, to aid in understanding the standard and its requirements. <u>Rationale</u> text boxes and other text boxes are also inserted throughout the standard to aid understanding the sections. The <u>Effective Dates</u> section covers five special cases for lines that undergo specific transitions as or after the standard has reached the general effective date.

Preface

The NERC Vegetation Management Standard Drafting Team (VM SDT) acknowledges those across the industry who contributed to the development of this Standard and companion Technical Reference document. This Technical Reference document is intended to provide supplemental explanatory background and guidance related to requirements contained in the Standard but does not in itself contain requirements subject to compliance review.

The Standard requires the Transmission Owner to have documentation of the maintenance strategies or procedures or processes or specifications it uses to be successful in managing vegetation. This allows the Transmission Owner to exercise substantial flexibility in designing its overall program to meet its specific needs provided that the Transmission Owner also meets the purpose of the Standard.

While there are many approaches to vegetation management, the VMSDT supports industry best practices contained in ANSI A300 (Part 7) – Integrated Vegetation Management (IVM) practices on Utility Rights-of-way, as well as the companion publication Best Management Practices – Integrated Vegetation Management, as an effective strategy to maintain compliance with this Standard. ANSI A300 (Part 7), approved by industry consensus in 2006, contains many elements needed for an effective vegetation management. Those elements are similar to the requirements in this Standard. One key element is the "wire zone – border zone" concept. Supported by over 50 years of continuous research, wire zone – border zone is a proven method to manage vegetation on transmission rights-of-ways and is an industry accepted best practice to help ensure electric system reliability.

The VM SDT believes that Transmission Owners who adopt and effectively implement IVM principles, particularly the "wire zone – border zone" concept, are far less likely to experience a vegetation caused outage than those who do not.

Effective Dates & Special States of Transition

The first sentence of the Effective Dates section is standard language used in most NERC standards to cover the general effective date and is sufficient to cover the vast majority of situations. Five special cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the standard. The text for each of these five cases is copied from the standard and is shown below in italic font. An explanation of the need for each special exception follows each copied text section.

1. *A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.*

Case 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effective for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on the January 1 of the PY specified with an allowance of at least 12 months for the Transmission Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.

Date that Planning Study is completed	PY the line will become an IROL element	Date 1	Date 2	Effective Date The latter of Date 1 or Date 2
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

2. *A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.*

Case 2 is needed because a line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

3. *A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date*

Case 3 is needed because a line operating at 200 kV or above that once was designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.

4. *An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.*

Case 4 is needed because an existing line that is to be operated at 200 kV or above can be acquired by a Transmission Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the Transmission owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network which will thereafter make the line subject to the standard.

5. *An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.*

Case 5 is needed because an existing line that is operated below 200 kV can be acquired by a Transmission Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the Transmission owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network. In this special case the line upon acquisition was designated as an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC transfer Path.

Definition of Terms

Right-of-Way (ROW)*

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.

> The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

The current NERC glossary definition of Right of Way has been modified to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of "right of way" in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

This definition does not imply that danger tree rights beyond the constructed and maintained width are incorporated in the definition; therefore fall-ins from outside the ROW but within an area with danger tree rights would not be considered fall-ins from within the ROW.

Vegetation Inspection*

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

The inspection includes the identification of any vegetation that may pose a threat to reliability

> The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.
>
> Current definition of Vegetation Inspection: The systematic examination of a transmission corridor to document vegetation conditions.

prior to the next planned maintenance or inspection work, considering the current location of the conductor and other possible locations of the conductor due to sag and sway for rated conditions.

This definition allows both maintenance inspections and vegetation inspections to be performed concurrently.

* This is a modification to a defined term in the NERC glossary and will be incorporated into the NERC glossary of terms with final approval of this standard revision.

See the Guidelines and Technical Basis section on Requirement R6 contained within the Standard for more details on inspections.

Minimum Vegetation Clearance Distance (MVCD)

The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method has been in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figures 1, 2 and 3. Details of the equations and an example calculation are provided in Appendix 1below of the Technical Reference document. Table 1in Appendix 1 below provides MVCD values for various voltages and altitudes.

Applicability of the Standard

4. Applicability

4.1. Functional Entities:
Transmission Owners

4.2. Facilities: *Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal*[1]*, state, provincial, public, private, or tribal entities:*

_4.2.1_ *Each overhead transmission lines operated at 200kV or higher.*

_4.2.2_ *Each overhead transmission lines operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.*

_4.2.3_ *Each overhead transmission lines operated below 200 kV identified as an element of a Major WECC Transfer Paths in the Bulk Electric System by WECC.*

_4.2.4_ Each overhead transmission line identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span *of the transmission line that is crossing the substation fence.*

4.3. Enforcement: *The reliability obligations of the applicable entities and facilities are contained within the technical requirements of this standard*

Rationale

The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) NERC has a project in place to address at a later date the applicability of this standard to Generation Owners. 4) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

In Order 693, FERC discussed the 200 kV bright-line test of applicability. While FERC did not change the 200 kV bright-line, the Commission remained concerned that there may be some transmission lines operating at lesser voltages that could have significant impact on the Bulk Electric System that should therefore be subject to this standard.

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies"*.

NERC Standard FAC-014 has the stated purpose, "*To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.*" FAC-014 requires Reliability Coordinators, Planning Coordinators, and Transmission Planners to have a methodology to identify all lines that might comprise an IROL. Thus, these entities would identify sub-200 kV lines that qualify as part of an IROL and should be subject to FAC-003-2.

Although all three entities may prepare the list of elements, the list as provided by the Planning Coordinator function is the more appropriate choice for this Standard. The Time Horizon needed to plan vegetation management work does not lend itself to the operating horizon of a Reliability Coordinator. Additionally, the Planning Coordinator has a wider-area view than the Transmission Planner and could thus identify any elements of importance to a sub-set of its area that might be missed by a Transmission Planner.

Transmission Owners, who do not already get the list of circuits included in the definition of an IROL, can get them from the Planning Coordinator. Specifically R5 of FAC-014 specifies that "*The Reliability Coordinator, Planning Authority (Coordinator) and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits*"

Vegetation-related Sustained Outages that occur due to natural disasters are beyond the control of the Transmission Owner. These events are not classified as vegetation-related Sustained Outages and are therefore exempt from the Standard. Transmission lines are not designed to withstand the impacts of natural disasters such as flood, drought, earthquake, major storms, fire, hurricane, tornado, landslides, ice storms, etc. In the aftermath of catastrophic system damage from natural disasters the Transmission Owner's focus is on electric system restoration for public safety and critical support infrastructure.

Sustained Outages due to human or animal activity are beyond the control of the Transmission Owner. These outages are not classified as vegetation-related Sustained Outages and are therefore exempt from the Standard. Examples of these events may include new plantings by outside parties of tall vegetation under the transmission line planted since the last Vegetation Inspection, tree contacts with line initiated by vehicles, logging activities, etc.

The foregoing exemptions are addressed in a new footnote 2. Referred to collectively as force majeure events and activities, this footnote applies to requirements R1 and R2 in FAC-003-2.

The reliability objective of this NERC Vegetation Management Standard ("Standard") is to prevent vegetation-related outages which could lead to Cascading by effective vegetation maintenance while recognizing that certain outages such as those due to vandalism, human errors and acts of nature are not preventable. Operating experience clearly indicates that trees that have grown out of specification could contribute to a cascading grid failure, especially under heavy electrical loading conditions.

Serious outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. To properly reduce and manage this risk, it is necessary to apply the Standard to applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee. For the purposes of the Standard and this Technical Reference document, the term “public lands” includes municipal lands, village lands, city lands, and land owned by a host of other governmental entities.

The Standard addresses vegetation management along applicable overhead lines that serve to connect one electric station to another. However, it is not intended to be applied to lines sections inside the electric station fence or other boundary of an electric station, submarine or underground lines.

The Standard is intended to reduce the risk of Cascading involving vegetation. It is not intended to prevent customer outages from occurring due to tree contact with all transmission lines and voltages. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this Standard is not written to address such isolated situations which have little impact on the overall Bulk Electric System.

Vegetation growth is constant and always present. Unmanaged vegetation below numerous transmission lines that are operating at or near their Rating is highly problematic. This situation has led to multiple subsequent line failures and Cascading. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are statistically intermittent. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this Standard’s emphasis is on vegetation grow-ins.

In preparing the original vegetation management standard in 2005, industry stakeholders set the threshold for applicability of the standard at 200kV. This was because an unexpected loss of lines operating at above 200kV has a higher probability of initiating a widespread blackout or cascading outages compared with lines operating at less than 200kV.

The original NERC Standard FAC-003-1 also allowed for application of the standard to “critical” circuits (critical from the perspective of initiating widespread blackouts or cascading outages) operating below 200kV. While the percentage of these circuits is relatively low, it remains a fact that there are sub-200kV circuits whose loss could contribute to a widespread outage. Given the very limited exposure and unlikelihood of a major event related to these lower-voltage lines, it would be an imprudent use of resources to apply the Standard to all sub-200kV lines. The drafting team, after evaluating several alternatives, selected the IROL and WECC Major Transfer Path criteria to determine applicable lines below 200 kV that are subject to this standard.

Requirements R1 and R2

R1. Each Transmission Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[2]:

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage[3],
2. An encroachment due to a fall-in from inside the Right-of-Way (ROW) that caused a vegetation-related Sustained Outage[4],
3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[4],
4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage[4].

R2. Each Transmission Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer

Rationale for R1 and R2:

Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a Transmission Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.

2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.

3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.

4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

[2] This requirement does not apply to circumstances that are beyond the control of a Transmission Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

[3] If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

[4] Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[2]:

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage[3],
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage[4],
3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[4],
4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage[4]

M1. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

M2. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the prevention of vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each Transmission Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element of an IROL or Major WECC transfer path. R2 is applicable to all other lines that are not an element of an IROL, and not an element of a Major WECC Transfer Path.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not an element of an IROL or a Major WECC Transfer Path. Applicable lines that are not an element of an IROL or Major WECC Transfer Path do require effective vegetation management, but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

R1 and R2 state that if vegetation encroaches within the distances in Table 1 in Appendix 1 of this supplemental Technical Reference document, it is in violation of the standard. Table 1below, which is the same as Table 2 in the standard, tabulates the distances necessary to prevent spark-over based on the Gallet equations as described more fully in Appendix 1 below.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by a Transmission Operator or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of a Transmission Owner to <u>manage</u> vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with a Transmission Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

If the TO has applicable lines operated at nominal voltage levels not listed in Table 2, then the TO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

Requirement R3

Rationale

The documentation provides a basis for evaluating the competency of the Transmission Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the Transmission Owner avoids vegetation-to-wire conflicts under all Rated Electrical Operating Conditions. See Figure 1 for an illustration of possible conductor locations.

R3. *Each Transmission Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable transmission lines that accounts for the following:*

3.1 *Movement of applicable line conductors under their Facility Rating and all Rated Electrical Operating Conditions;*

3.2 *Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.*

M3. *The maintenance strategies or procedures or processes or specifications provided demonstrate that the Transmission Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)*

Requirement R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, a Transmission Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the Transmission Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources and the competency of the Transmission Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the Transmission Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7.

However, regardless of the approach a utility uses to manage vegetation, any approach a Transmission Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the Transmission Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*

4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figures 1, 2, and 3 below.

Conductor Dynamics

In order for a Transmission Owner to develop a specific maintenance approach, it is important to understand the dynamics of a line conductor's movements. This paper will first address the complexities inherent in observing and predicting conductor movement, particularly for field personnel. It will then present some examples of maintenance approaches which Transmission Owners may consider that take into account these complexities, and the practical approaches that can be utilized by field personnel.

Additionally, it is important the Transmission Owner consider all conductor locations, the MVCD, and vegetation growth between maintenance activities when developing a maintenance approach.

Understanding Conductor Position and Movement

The conductor's position in space at any point in time is continuously changing as a reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading.

As a consequence of these loading variables, the conductor's position in space is dynamic and moving. When calculating the range of conductor positions, the Transmission Owner should use the same design criteria and assumptions that are used to establish Ratings and System Operating Limits (SOLs), as described in other standards. Typically, the greatest conductor movements occur at mid-span. As the conductor moves through various positions, a spark-over zone surrounding the conductor moves with it. The radius of the spark-over zone may be found by referring to Table 1 below. For illustrations of this zone and conductor movements, Figures 1, 2 and 3 below are provided. At the time of making a field observation, however, it is very difficult to precisely know where the conductor is in relation to its wide range of all possible positions. Therefore, Transmission Owners must adopt maintenance approaches that account for this dynamic situation.

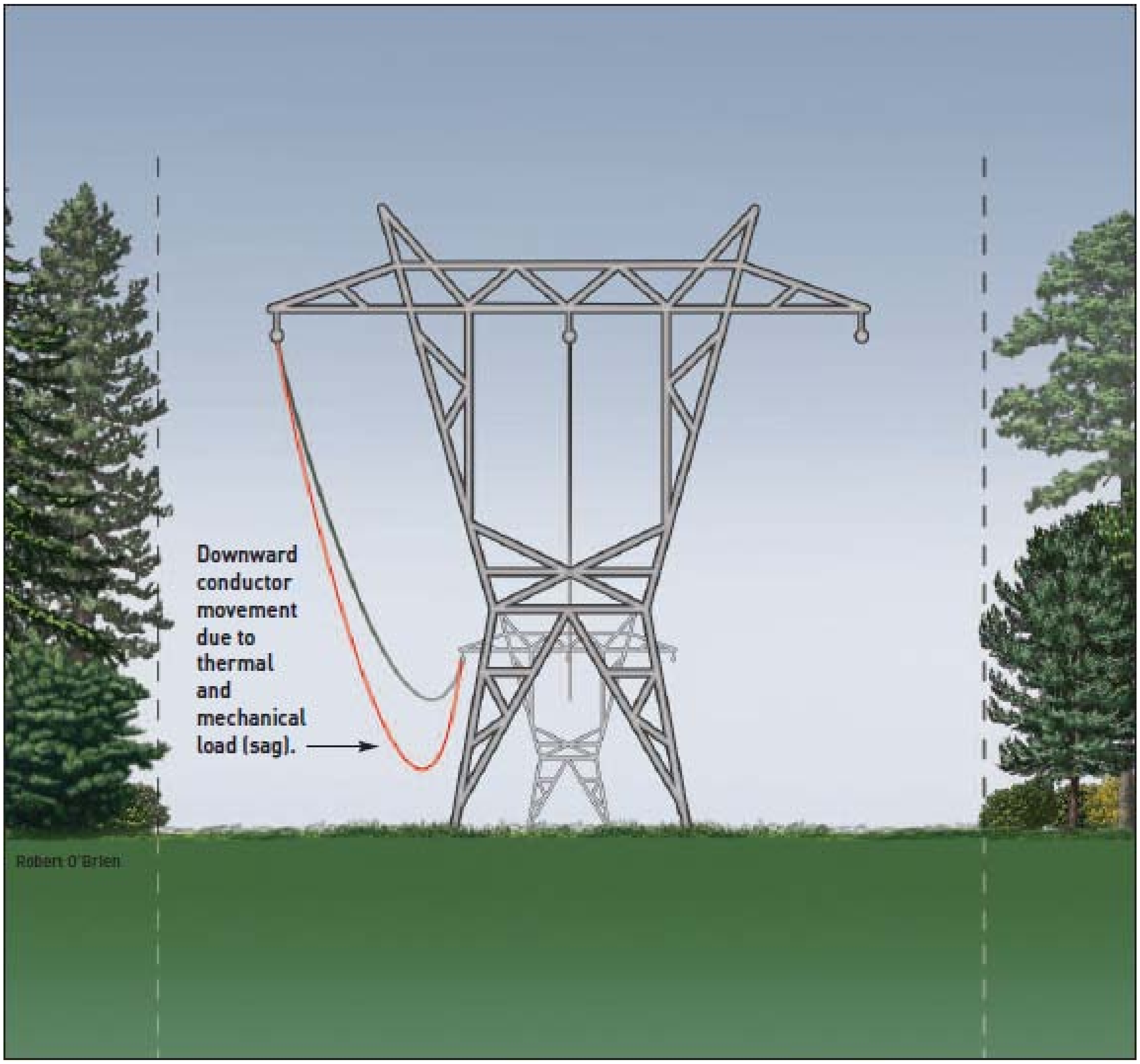
Downward
conductor
movement
due to
thermal
and
mechanical
load (sag).
Robert O'Brien

Figure 1

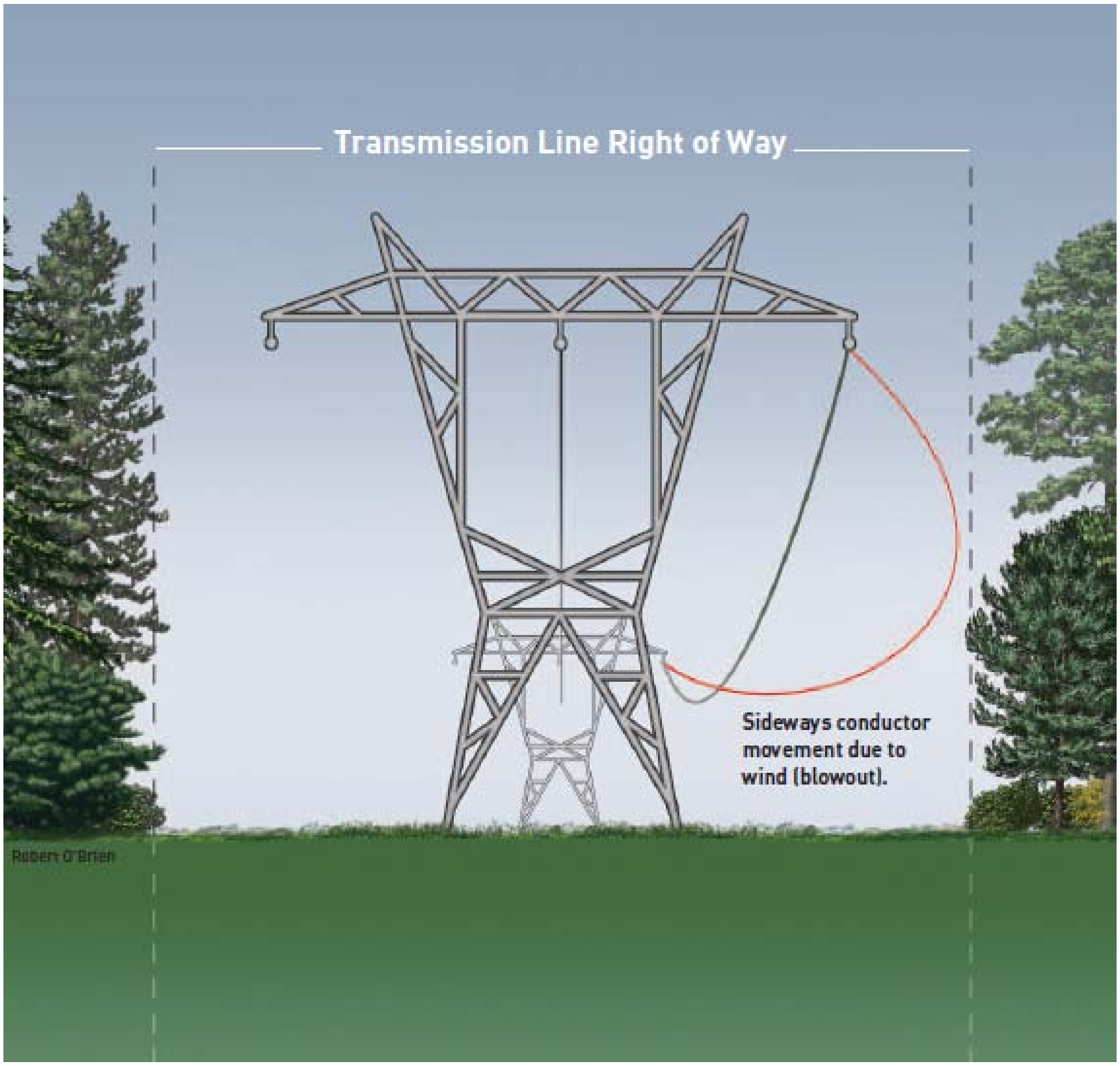
Transmission Line Right of Way
Sideways conductor movement due to wind (blowout).
Robert O'Brien

Figure 2

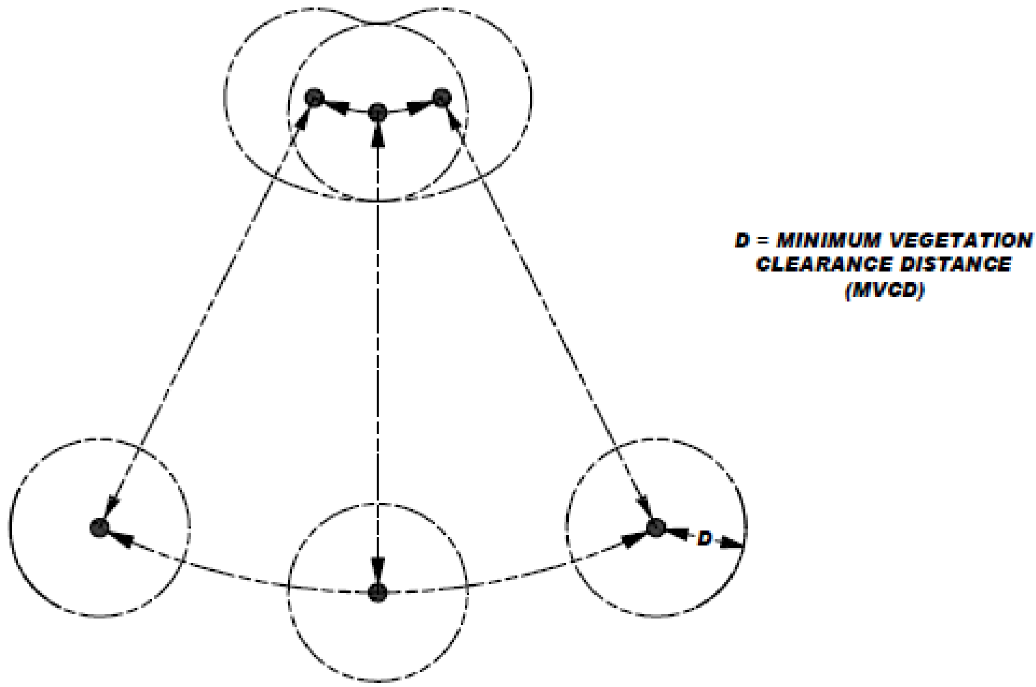

Figure 3

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

Selecting a Maintenance Approach

In order to maintain adequate separation between vegetation and transmission line conductors, the Transmission Owner must craft a maintenance strategy that keeps vegetation well away from the spark-over zone mentioned above. In fact, it is generally necessary to incorporate a variety of maintenance strategies. For example, one Transmission Owner may utilize a combination of routine cycles, traditional IVM techniques and long-term planning. Another Transmission Owner may place a higher reliance on frequent inspections and follow-up remediation as opposed to a set cyclical approach. This variation of approaches is further warranted when factors, such as terrain, vegetation types, weather and climate, and any, environmental, legal or other land use constraints, must be considered in developing a Transmission Owner's specific approach to satisfying R3.

The following describes some strategies which may be utilized by a Transmission Owner. A Transmission Owner's basic maintenance approach in relatively flat terrain could be to remove all incompatible vegetation from the ROW if it has the right to do so and has no constraints. In mountainous terrain, however, this strategy could change to managing vegetation based on vegetation-to-conductor clearances, since it might not be necessary to remove vegetation in a valley that is far below the conductors at maximum sag.

If faced with easement constraints on a line design with sufficient ground clearance, the approach could be to allow vegetation such as fruit trees, but only up to a given height at maturity (for example 10 feet from the ground). If constraints cannot be overcome and if design clearances are sufficient, an exception to the Transmission Owner's 10-foot guideline might be made. If an approach is chosen to manage vegetation based primarily on clearance distances it could include an inspection regimen to regularly ensure that impending clearance problems are identified early for rectification.

ANSI A300 – Best Management Practices for Tree Care Operations

A description of ANSI A-300, part 7, is offered below to illustrate another maintenance approach that could be used in developing a comprehensive transmission vegetation management program.

Introduction

Integrated Vegetation Management (IVM) is a best management practice conveyed in the American National Standard for Tree Care Operations, Part 7 (ANSI 2006) and the International Society of Arboriculture *Best Management Practices: Integrated Vegetation Management* (Miller 2007). IVM is consistent with the requirements in FAC-003-02, and it provides practitioners with what industry experts consider to be appropriate techniques to apply to electric right-of-way projects in order to meet or exceed the Standard.

IVM is a system of managing plant communities whereby managers set objectives; identify compatible and incompatible vegetation; consider action thresholds; and evaluate, select and implement the most appropriate control method or methods to achieve set objectives. The choice of control method or methods should be based on the environmental impact and anticipated effectiveness; along with site characteristics, security, economics, current land use and other factors.

Planning and Implementation

Best management practices provide a systematic way of planning and implementing a vegetation management program. While designed primarily with transmission systems in mind, it is also applicable to distribution projects. As presented in ANSI A300 part 7 and the ISA best management practices, IVM consists of 6 elements:

1) Set Objectives
2) Evaluate the Site
3) Define Action Thresholds
4) Evaluate and Select Control Methods
5) Implement IVM
6) Monitor Treatment and Quality Assurance

The setting of objectives, defining action thresholds, and evaluating and selecting control methods all require decisions. The planning and implementation process is cyclical and continuous, because vegetation is dynamic and managers must have the flexibility to adjust their plans. Adjustments may be made at each stage as new information becomes available and circumstances evolve.

Set Objectives

Objectives should be clearly defined and documented. Examples of objectives can include promoting safety, preventing sustained outages caused by vegetation growing into electric facilities, maintaining regulatory compliance, protecting structures and security, restoring electric service during emergencies, maintaining access and clear lines of sight, protecting the environment, and facilitating cost effectiveness. Objectives should be based on site factors, such as workload and vegetation type, in addition to human, equipment and financial resources. They will vary from utility to utility and project to project, depending on line voltage and criticality, as well as topographical, environmental, fiscal and political considerations. However, where it is appropriate, the overriding focus should be on environmentally-sound, cost effective control of species that potentially conflict with the electric facility, while promoting compatible, early successional, sustainable plant communities.

Work Load Evaluations

Work-load evaluations are inventories of vegetation that could have a bearing on management objectives. Work load assessments can capture a variety of vegetation characteristics, such as location, height, species, size and condition, hazard status, density and clearance from conductors. Assessments should be conducted considering voltage, conductor sag from ambient temperatures and loading, and the potential influence of wind on line sway.

Evaluate and Select Control Methods

Control methods are the process through which managers achieve objectives. The most suitable control method best achieves management objectives at a particular site. Many cases call for a combination of methods. Managers have a variety of controls from which to choose, including manual, mechanical, herbicide and tree growth regulators, biological, and cultural options.

Manual Control Methods

Manual methods employ workers with hand-carried tools, including chainsaws, handsaws, pruning shears and other devices to control incompatible vegetation. The advantage of manual techniques is that they are selective and can be used where others may not be. On the other hand, manual techniques can be inefficient and expensive compared to other methods.

Mechanical Control Methods

Mechanical controls are done with machines. They are efficient and cost effective, particularly for clearing dense vegetation during initial establishment, or reclaiming neglected or overgrown right of way. On the other hand, mechanical control methods can be non-selective and disturb sensitive sites.

Tree Growth Regulator and Herbicide Control Methods

Tree growth regulators and herbicides can be effective for vegetation management. Tree growth regulators (TGRs) are designed to reduce growth rates by interfering with natural plant processes. TGRs can be helpful where removals are prohibited or impractical by reducing the growth rates of some fast-growing species.

Herbicides control plants by interfering with specific botanical biochemical pathways. Herbicide use can control individual plants that are prone to re-sprout or sucker after removal. When trees that re-sprout or sucker are removed without herbicide treatment, dense thickets develop, impeding access, swelling workloads, increasing costs, blocking lines-of-site, and deteriorating wildlife habitat. Treating suckering plants allows early successional, compatible species to dominate the right-of-way and out-compete incompatible species, ultimately reducing work.

Cultural Control Methods

Cultural methods modify habitat to discourage incompatible vegetation and establish and manage desirable, early successional plant communities. Cultural methods take advantage of seed banks of native, compatible species lying dormant on site. In the long run, cultural control is the most desirable method where it is applicable.

A cultural control known as cover-type conversion provides a competitive advantage to short-growing, early successional plants, allowing them to thrive and eventually out-compete unwanted tree species for sunlight, essential elements and water. The early successional plant community is relatively stable, tree-resistant and reduces the amount of work, including herbicide application, with each successive treatment.

Wire-Border Zone

The wire-border zone technique is a management philosophy that can be applied through cultural control. W.C. Bramble and W.R. Byrnes developed it in the mid-1980s out of research begun in 1952 on a transmission right-of-way in the Pennsylvania State Game Lands 33 Research and Demonstration project (Yahner and Hutnik (2004).

The wire zone is the section of a utility transmission right-of-way directly under the wires and extending outward about 10 feet on each side. The wire zone is managed to promote a low-growing plant community dominated by grasses, herbs and small shrubs (under 3 feet in height at maturity). The border zone is the remainder of the right-of-way. It is managed to establish small trees and tall shrubs (under 25 feet in height at maturity). When properly managed, diverse, tree-resistant plant communities develop in wire and border zones. The communities not only protect the electric facility and reduce long-term maintenance, but also enhance wildlife habitat, forest ecology and aesthetic values.

Although the wire-border zone is a best practice in many instances, it is not necessarily universally suitable. For example, standard wire-border zone prescriptions may be unnecessary where lines are high off the ground, such as across low valleys or canyons, so the technique can be modified without sacrificing reliability.

One way to accommodate variances in topography is to establish different regions based on wire height. For example, over canyon bottoms or other areas where conductors are 100 feet or more above the ground, only a few trees are likely to be tall enough to conflict with the lines. In those cases, trees that potentially interfere with the transmission lines can be removed selectively on a case-by-case basis.

In areas where the wire is lower, perhaps between 50-100 feet from the ground, a border zone community can be developed throughout the right-of-way. Note that in many cases, conductor attachment points are more than 50 feet off the ground, so a border zone community can be cultivated near structures. Where the line is less than 50 feet off the ground, managers could apply a full wire-border zone prescription.

An environmental advantage of this type of modification is stream protection. Streams often course through the valleys and canyons where lines are likely to be elevated. Leaving timber or border zone communities in canyon bottoms helps shelter this valuable habitat, enabling managers to achieve environmentally sensitive objectives.

Implement IVM

All laws and regulations governing IVM practices and specifications written by qualified vegetation managers must be followed. Integrated vegetation management control methods should be implemented on regular work schedules, which are based on established objectives and completed assessments. Work should progress systematically, using control measures determined to be best for varying conditions at specific locations along a right-of-way. Some considerations used in developing schedules include the importance and type of line, vegetation clearances, workloads, growth rate of predominant vegetation, geography, accessibility, and in some cases, time lapsed since the last scheduled work.

Clearances Following Work

Clearances following work should be sufficient to meet management objectives, including preventing trees from entering the Minimum Vegetation Clearance Distance, electric safety risks, service-reliability threats and cost.

Monitor Treatment and Quality Assurance

An effective program includes documented processes to evaluate results. Evaluations can involve quality assurance while work is underway and after it is completed. Monitoring for quality assurance should begin early to correct any possible miscommunication or misunderstanding on the part of crewmembers. Early and consistent observation and evaluation also provides an opportunity to modify the plan, if need be, in time for a successful outcome.

Utility vegetation management programs should have systems and procedures in place for documenting and verifying that vegetation management work was completed to specifications. Post-control reviews can be comprehensive or based on a statistically representative sample. This final review points back to the first step and the planning process begins again.

Summary of A-300 example

Integrated Vegetation Management offers among others, a systematic way of planning and implementing a vegetation management program as presented in ANSI A300 Part 7. This methodology enables a program to comply with the NERC *Transmission Vegetation Management Program* standard (FAC-003-2). Managers should select control options to best promote management objectives.

Vegetation Inspections

The standard in R6 establishes the frequency of vegetation inspections. These inspections can be used to “evaluate the site” as referred to in the second element of ANSI A300 Part 7. This necessary frequency may need to be less than the annually based on anticipated growth rates of the local vegetation, length of the growing season for the geographical area, limited ROW width, rainfall amounts, etc.

Annual Work Plan

Requirement R7 of the Standard addresses the execution of the annual work plan. A comprehensive approach that exercises the full extent of legal rights is superior to incremental management in the long term because it reduces overall encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient at all locations on the ROW. Removal is superior to pruning. Removal minimizes the possibility of conflicts between energized conductors and vegetation. When this is not possible, the approach should be to use vegetation maintenance methods to work towards or achieve the maximum use of the ROW.

Requirement R4

R4. *Each Transmission Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable transmission line when the Transmission Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment.*

Rationale

This is to ensure expeditious communication between the Transmission Owner and the control center when a critical situation is confirmed.

M4. *Each Transmission Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)*

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the Transmission Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of a Transmission Owner's employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The Transmission Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or positioning the system in recognition of the increasing risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some Transmission Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5

R5. *When a Transmission Owner is constrained from performing vegetation work on an applicable line operating within their Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the Transmission Owner shall take corrective action to ensure continued vegetation management to prevent encroachments.*

M5. *Each Transmission Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that a line was de-energized. (R5)*

Rationale

Legal actions and other events may occur which result in constraints that prevent the Transmission Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the Transmission Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the Transmission Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the Transmission Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the Transmission Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the Transmission Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the Transmission Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the Transmission Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for each location.
- In developing the specific action to mitigate the potential risk to the transmission line the Transmission Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The Transmission Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6

R6. *Each Transmission Owner shall perform a Vegetation Inspection of 100% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 months between inspections on the same ROW.*[5]

M6. *Each Transmission Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)*

Rationale

Inspections are used by Transmission Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections that fits general industry practice. In addition, the fact that Vegetation Inspections can be performed in conjunction with general line inspections further facilitates a Transmission Owner's ability to meet this requirement. However, the Transmission Owner may determine that more frequent inspections are needed to maintain reliability levels, dependent upon such factors as anticipated growth rates of the local vegetation, length of the growing season for the geographical area, limited ROW width, and rainfall amounts. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

Footnote 5 is added to address the situation where a Transmission Owner through no fault of its own, would be unable to complete the vegetation inspection within the allotted time period. This would include the situation of mutual aid as well as disasters to the Transmission Owner's own system.

[5] When the Transmission Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO is granted a time extension that is equivalent to the duration of the time the TO was prevented from performing the Vegetation Inspection.

The VSL for Requirement R6 has VSL categories ranked by the percentage of the required ROW inspections completed. To calculate the percentage of inspection completion, the Transmission Owner may choose units such as: line miles or kilometers, circuit miles or kilometers, pole line miles, ROW miles, etc.

For example, when a Transmission Owner operates 2,000 miles of applicable transmission lines this Transmission Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%.

The “Low VSL” for R6 would apply in this example.

Requirement R7

R7. *Each Transmission Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include:*

Rationale

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of a Transmission Owner[6]
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

M7. *Each Transmission Owner has evidence that it completed its annual vegetation work plan. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (including modifications if any), dated work orders, dated invoices, or dated inspection records. (R7)*

R7 is a risk-based requirement. The Transmission Owner is required to implement its work plan for vegetation management to accomplish the purpose of this Standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual

[6] Circumstances that are beyond the control of a Transmission Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or an applicable regulatory body.

work plan requirement is not intended to necessarily require a "span-by-span", or even a "line-by-line" detailed description of all work to be performed. It is only intended to require that the Transmission Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

For example, when a Transmission Owner identifies 1,000 miles of applicable transmission lines to be completed in the TO's annual plan, the Transmission Owner will be responsible completing those identified miles. If a TO makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be: 1000 – 100 (deferred miles) = 900 modified annual plan, or 900 / 900 = 100% completed annual miles. If a TO only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: 1000 – 875 = 125 miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the Transmission Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance or work may be deferred to a subsequent year because of slower-than-expected growth. This situation may also include complying with mutual assistance agreements by moving resources off the Transmission Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan. Modifications to the annual work plan must always ensure the reliability of the electric Transmission system.

In general, the vegetation management maintenance approach should use the full extent of the Transmission Owner's legal rights on the ROW. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management in the long term because it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the Transmission Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Transmission Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the Transmission Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned

versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs and walk-through reports.

Appendix 1: Clearance Distance Derivation by the Gallet Equation

The Gallet Equation is a well-known method of computing the required strike distance for proper insulation coordination, and has the ability to take into account various air gap geometries, as well as non-standard atmospheric conditions. When the Gallet Equation and conservative probabilistic methods are combined, i.e. deterministic design, spark-over probabilities of 10^{-6} or less are achieved. This approach is well known for its conservatism and was used to design the first 500 kV and 765 kV lines in North America [1]. Thus, the deterministic design approach using the Gallet Equation is used for the standard to compute the minimum strike distance between transmission lines and the vegetation that may be present in or along the transmission corridor.

Method Explanation (Gallet Equation)

In 1975 G. Gallet published a benchmark paper that provided a method to compute the critical flashover voltage (CFO) of various air gap geometries [4]. The Gallet Equation uses various “gap factors” to take into account various air gap geometries. Various gap factor values are provided in [1]. If the vegetation in a transmission corridor, e.g. a tree, is assumed electrically to be a large structure then the CFO of such an air gap geometry can be computed for dry or wet conditions using a well established equation proposed by Gallet [1],[2],[4],

$$CFO_A = k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} \qquad (1)$$

where,

k_w is defined as the factor that takes into account wet or dry conditions (dry = 1.0 and wet = 0.96) and phase arrangement (multiply by 1.08 for outside phase), e.g. outside phase and wet conditions = (0.96)(1.08) = 1.037,

k_g is defined as the gap factor (1.3 for conductor to large structure),

D is the strike distance (m),

CFO_A is the CFO for the relative air density (kV).

δ is defined as the relative air density and is approximately equal to (2) where A is the altitude in km,

$$\delta = e^{-\frac{A}{8.6}} \tag{2}$$

$$m = 1.25G_0 \left(G_0 - 0.2\right) \tag{3}$$

$$G_0 = \frac{CFO_s}{500 \cdot D} \tag{4}$$

$$CFO_s = k_w \cdot k_g \cdot \frac{3400}{1 + \frac{8}{D}} \tag{5}$$

where CFO_S is the CFO for standard atmospheric conditions (kV). Using (1)-(5), the required CFO_A can be computed using an iterative process.

Once the CFO_A is known, deterministic methods can be used to determine the required clearance distance. If we let the maximum switching overvoltage be equal to the withstand voltage of the air gap (CFO_A - 3σ) then the CFO_A can be written as (6).

$$CFO_A = \frac{V_m}{1 - 3\left(\frac{\sigma}{CFO_A}\right)} \tag{6}$$

where

V_m is equal to the maximum switching overvoltage, i.e. the value that has a 0.135% chance of being exceeded,

σ is the standard deviation of the air gap insulation,

CFO_A is the critical flashover voltage of the air gap insulation under non-standard atmospheric conditions.

The ratio of σ to the CFO_A given in (6) can be assumed to be 0.05 (5%) [1]. Thus, (6) can be written as (7).

$$CFO_A = \frac{V_m}{0.85} \tag{7}$$

Substituting (7) into (1) we arrive at (8).

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1 + \frac{8}{D}} \tag{8}$$

Equation 8 relates the maximum transient overvoltage, V_m, to the air gap distance, D. Using (8) to compute the required clearance distance for the specified air gap geometry (conductor to large structure) results in a probability of flashover in the range of 10^{-6}.

Transient Overvoltage

In general, the worst case transient overvoltages occurring on a transmission line are caused by energizing or re-energizing the line with the latter being the extreme case if trapped charge is present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to sparkover from the line conductor to nearby vegetation. Thus, the worst case scenarios that are typically analyzed for insulation coordination purposes (e.g. line energization and re-energization) can be ignored. For the purposes of FAC-003-2, the worst case transient overvoltage then becomes the maximum value that can occur with the line energized. Determining a realistic value of transient overvoltage for this situation is difficult because the maximum transient overvoltage factors listed in the literature are based on a switching operation of the line in question. In other words, these maximum overvoltage values (e.g. the values listed in [2], [3] and [5]) are based on the assumption that the subject line is being energized, re-energized or de-energized. These operations, by their very nature, will create the largest transient overvoltages. Typical values of transient overvoltages of in-service lines, as such, are not readily available in the literature because the resulting level of overvoltage is negligible compared with the maximum (e.g. re-energizing a transmission line with trapped charge). A conservative value for the maximum transient overvoltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 p.u.[2]. This value is a conservative estimate of the transient overvoltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without a pre-insertion device (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. 362 kV), the maximum transient overvoltage of an “in-service” ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 p.u. or less [2]. It is well known that these theoretical transient overvoltages will not be experienced at locations remote from the bus at which they were created; however, in order to be conservative, it will be assumed that all nearby ac lines are subjected to this same level of overvoltage. Thus, a maximum transient overvoltage factor of 2.0 p.u. for 302 kV and below and 1.4 p.u. for ac transmission lines 362 kV and above is used to compute the required clearance distances for vegetation management purposes.

The overvoltage characteristics of dc transmission lines vary somewhat from their ac counterparts. The referenced empirically derived transient overvoltage factor used to calculate the minimum clearance distances from dc transmission lines to vegetation for the purpose of FAC-003-2 will be 1.8 p.u.[3].

Example Calculation

An example calculation is presented below using the proposed method of computing the vegetation clearance distances. It is assumed that the line in question has a maximum operating voltage of 550 kV_{rms} line-to-line. Using a per unit transient overvoltage factor of 1.4, the result is a peak transient voltage of 629 kV_{crest}. It is further assumed that the line in question operates at a maximum altitude of 7000 feet (2.134 km) above sea level.

The required withstand voltage of the air gap must be equal to or greater than 629 kV_{crest}. Since the altitude is above sea level, (1) - (5) have to be iterated on to achieve the desired result. Equation (9) can be used as an initial guess for the clearance distance.

$$D_i = \frac{8}{\frac{3400 \cdot k_w \cdot k_g}{\left(\frac{V_m}{0.85}\right)} - 1} \tag{9}$$

For our case here, V_m is equal to 629 kV, k_w = 1.037 and k_g = 1.3. Thus,

$$D_i = \frac{8}{\frac{3400 \cdot k_w \cdot k_g}{\left(\frac{V_m}{0.85}\right)} - 1} = \frac{8}{\frac{3400 \cdot 1.037 \cdot 1.3}{\left(\frac{629}{0.85}\right)} - 1} = 1.535m \tag{10}$$

Using (2)-(5) and (8) the withstand voltage of the air gap is next computed. This value will then be compared to the maximum transient overvoltage.

$$CFO_S = k_w \cdot k_g \cdot \frac{3400}{1 + \frac{8}{D}} = 1.037 \cdot 1.3 \cdot \frac{3400}{1 + \frac{8}{1.535}} = 737.7kV \tag{11}$$

$$\delta = e^{-\frac{A}{8.6}} = e^{-\frac{2.134}{8.6}} = 0.78 \tag{12}$$

$$G_O = \frac{CFO_S}{500 \cdot D} = \frac{737.7}{(500) \cdot (1.535)} = 0.961 \tag{13}$$

$$m = 1.25 \cdot G_O (G_O - 0.2) = 1.25 \cdot 0.961(0.961 - 0.2) = 0.915 \tag{14}$$

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1 + \frac{8}{D}} = (0.85)(1.037)(1.3)(0.78)^{0.915} \left(\frac{3400}{1 + \frac{8}{1.535}} \right) = 499.8kV \tag{15}$$

The calculated V_m is less than 629 kV; thus, the clearance distance must be increased. A few iterations using (2)-(5) and (8) are required until the computed $V_m \geq 629$ kV. For this case it was found that D = 1.978 m (6.49 feet) yielded V_m = 629.3 kV. Using this clearance distance the following values were computed for the final iteration.

$$CFO_S = k_w \cdot k_g \cdot \frac{3400}{1+\frac{8}{D}} = 1.037 \cdot 1.3 \cdot \frac{3400}{1+\frac{8}{1.978}} = 908.5kV \tag{16}$$

$$\delta = e^{-\frac{A}{8.6}} = e^{-\frac{2.134}{8.6}} = 0.78 \tag{17}$$

$$G_O = \frac{CFO_S}{500 \cdot D} = \frac{908.5}{(500)\cdot(1.978)} = 0.919 \tag{18}$$

$$m = 1.25 \cdot G_O(G_O - 0.2) = 1.25 \cdot 0.919(0.919 - 0.2) = 0.825 \tag{19}$$

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} = (0.85)(1.037)(1.3)(0.78)^{0.825}\left(\frac{3400}{1+\frac{8}{1.978}}\right) = 629.3kV \tag{20}$$

Therefore, the minimum vegetation clearance distance for a maximum line to line ac operating voltage of 550 kV at 7000 feet above sea level is 1.978 m (6.49 feet). Table 1 provides calculated distances for various altitudes and maximum system operating ac voltages.

Table 1 — Minimum Vegetation Clearance Distances (MVCD)[7]
For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)	(AC) Maximum System Voltage (kV)[8]	MVCD (feet) Over sea level up to 500 ft	MVCD (feet) Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft
765	800	8.2ft	8.33ft	8.61ft	8.89ft	9.17ft	9.45ft	9.73ft	10.01ft	10.29ft	10.57ft	10.85ft	11.13ft
500	550	5.15ft	5.25ft	5.45ft	5.66ft	5.86ft	6.07ft	6.28ft	6.49ft	6.7ft	6.92ft	7.13ft	7.35ft
345	362	3.19ft	3.26ft	3.39ft	3.53ft	3.67ft	3.82ft	3.97ft	4.12ft	4.27ft	4.43ft	4.58ft	4.74ft
287	302	3.88ft	3.96ft	4.12ft	4.29ft	4.45ft	4.62ft	4.79ft	4.97ft	5.14ft	5.32ft	5.50ft	5.68ft
230	242	3.03ft	3.09ft	3.22ft	3.36ft	3.49ft	3.63ft	3.78ft	3.92ft	4.07ft	4.22ft	4.37ft	4.53ft
161*	169	2.05ft	2.09ft	2.19ft	2.28ft	2.38ft	2.48ft	2.58ft	2.69ft	2.8ft	2.91ft	3.03ft	3.14ft
138*	145	1.74ft	1.78ft	1.86ft	1.94ft	2.03ft	2.12ft	2.21ft	2.3ft	2.4ft	2.49ft	2.59ft	2.7ft
115*	121	1.44ft	1.47ft	1.54ft	1.61ft	1.68ft	1.75ft	1.83ft	1.91ft	1.99ft	2.07ft	2.16ft	2.25ft
88*	100	1.18ft	1.21ft	1.26ft	1.32ft	1.38ft	1.44ft	1.5ft	1.57ft	1.64ft	1.71ft	1.78ft	1.86ft
69*	72	0.84ft	0.86ft	0.90ft	0.94ft	0.99ft	1.03ft	1.08ft	1.13ft	1.18ft	1.23ft	1.28ft	1.34ft

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above).

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[7] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[8] Where applicable lines are operated at nominal voltages other than those listed, The Transmission Owner should use the maximum system voltage to determine the appropriate clearance for that line.

Table 1 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[7]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)	(AC) Maximum System Voltage (kV)[8]	MVCD meters Over sea level up to 152.4m	MVCD meters Over 152.4m up to 304.8m	MVCD meters Over 304.8m up to 609.6m	MVCD meters Over 609.6m up to 914.4m	MVCD meters Over 914.4m up to 1219.2m	MVCD meters Over 1219.2m up to 1524m	MVCD meters Over 1524 m up to 1828.8m	MVCD meters Over 1828.8m up to 2133.6m	MVCD meters Over 2133.6m up to 2438.4m	MVCD meters Over 2438.4m up to 2743.2m	MVCD meters Over 2743.2m up to 3048m	MVCD meters Over 3048m up to 3352.8m
765	800	2.49m	2.54m	2.62m	2.71m	2.80m	2.88m	2.97m	3.05m	3.14m	3.22m	3.31m	3.39m
500	550	1.57m	1.6m	1.66m	1.73m	1.79m	1.85m	1.91m	1.98m	2.04m	2.11m	2.17m	2.24m
345	362	0.97m	0.99m	1.03m	1.08m	1.12m	1.16m	1.21m	1.26m	1.30m	1.35m	1.40m	1.44m
287	302	1.18m	0.88m	1.26m	1.31m	1.36m	1.41m	1.46m	1.51m	1.57m	1.62m	1.68m	1.73m
230	242	0.92m	0.94m	0.98m	1.02m	1.06m	1.11m	1.15m	1.19m	1.24m	1.29m	1.33m	1.38m
161*	169	0.62m	0.64m	0.67m	0.69m	0.73m	0.76m	0.79m	0.82m	0.85m	0.89m	0.92m	0.96m
138*	145	0.53m	0.54m	0.57m	0.59m	0.62m	0.65m	0.67m	0.70m	0.73m	0.76m	0.79m	0.82m
115*	121	0.44m	0.45m	0.47m	0.49m	0.51m	0.53m	0.56m	0.58m	0.61m	0.63m	0.66m	0.69m
88*	100	0.36m	0.37m	0.38m	0.40m	0.42m	0.44m	0.46m	0.48m	0.50m	0.52m	0.54m	0.57m
69*	72	0.26m	0.26m	0.27m	0.29m	0.30m	0.31m	0.33m	0.34m	0.36m	0.37m	0.39m	0.41m

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

Table 1 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[7]

For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV) Over sea level up to 500 ft (Over sea level up to 152.4 m)	(DC) Nominal Pole to Ground Voltage (kV) Over 500 ft up to 1000 ft (Over 152.4 m up to 304.8 m	(DC) Nominal Pole to Ground Voltage (kV) Over 1000 ft up to 2000 ft (Over 304.8 m up to 609.6m)	(DC) Nominal Pole to Ground Voltage (kV) Over 2000 ft up to 3000 ft (Over 609.6m up to 914.4m	(DC) Nominal Pole to Ground Voltage (kV) Over 3000 ft up to 4000 ft (Over 914.4m up to 1219.2m	(DC) Nominal Pole to Ground Voltage (kV) Over 4000 ft up to 5000 ft (Over 1219.2m up to 1524m	(DC) Nominal Pole to Ground Voltage (kV) Over 5000 ft up to 6000 ft (Over 1524 m up to 1828.8 m)	(DC) Nominal Pole to Ground Voltage (kV) Over 6000 ft up to 7000 ft (Over 1828.8m up to 2133.6m)	(DC) Nominal Pole to Ground Voltage (kV) Over 7000 ft up to 8000 ft (Over 2133.6m up to 2438.4m)	(DC) Nominal Pole to Ground Voltage (kV) Over 8000 ft up to 9000 ft (Over 2438.4m up to 2743.2m)	(DC) Nominal Pole to Ground Voltage (kV) Over 9000 ft up to 10000 ft (Over 2743.2m up to 3048m)	(DC) Nominal Pole to Ground Voltage (kV) Over 10000 ft up to 11000 ft (Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

List of Acronyms and Abbreviations

ANSI	American National Standards Institute
IEEE	Institute of Electrical and Electronics Engineers
IVM	Integrated Vegetation Management
NERC	North American Electric Reliability Corporation

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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Transmission Vegetation Management
Standard FAC-003-2 Technical Reference

Prepared by the

North American Electric Reliability Corporation

Vegetation Management Standard Drafting Team
for NERC Project 2007-07

September 30, 2011

Disclaimer

This supporting document is supplemental to the reliability standard FAC-003-2 — Transmission Vegetation Management and does not contain mandatory requirements subject to compliance review.~~December 17, 2010~~

Throughout this document, for ready reference, there are "copies" in italic font of the wording in the Standard. Any "copy" of any part of the Standard in this document should be cross checked to the Standard and if any difference exists, then the Standard's exact wording should be considered the intended wording for this document.

Introduction

This document is intended to provide supplemental information and guidance for complying with the requirements of Reliability Standard FAC-003-2.

The purpose of the Standard is to improve the reliability of the electric transmission system by preventing those vegetation related outages that could lead to Cascading.

Compliance with the Standard is mandatory and enforceable.

Special Note: The Application of the Results-Based Approach to FAC-003-2

In its three-year assessment as the ERO, NERC acknowledged stakeholder comments and committed to:

i) addressing quality issues to ensure each reliability standard has a clear statement of purpose, and has outcome-focused requirements that are clear and measurable; and
ii) eliminating requirements that do not have an impact on bulk power system reliability.

In 2010, the Standards Committee approved a recommendation to use Project 2007-07 Vegetation Management as a first proof of concept for developing results-based standards.

~~The Standard Drafting Team (SDT) employed a defense-in-depth[1] strategy for FAC-003-2, where each requirement has a role in preventing~~This standard is not intended to address outages such as those due to vegetation fall-ins or blow-ins from outside the Right-of-Way, vandalism, human activities or acts of nature. Operating experience indicates that trees that have grown out of specification have contributed to Cascading, especially under heavy electrical loading conditions.

This standard utilizes three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading~~. This portfolio of requirements was designed to achieve an overall defense-in-depth strategy and to comply with the quality objectives identified in the *Acceptance Criteria of a Reliability Standard* document.~~:

~~The SDT developed a portfolio of performance, risk, and competency-based mandatory reliability requirements to support an effective defense-in-depth strategy. Each Requirement was developed using one of the following requirement types:~~

a) Performance-based ~~-~~ — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome*?
b) Risk-based ~~-~~ — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome *that reduces a stated risk to the reliability of the bulk power system*?

~~[1] A defense-in-depth strategy for reliability standards recognizes that each requirement in the NERC standards has a role in preventing system failures, and that these roles are complementary and reinforcing. These prevention measures should be arranged in a series of defensive layers or walls. No single defensive layer provides complete protection from failure by itself. But taken together, with well-designed layers including performance, risk, and competency-based requirements, a defense-in-depth approach can be very effective in preventing future large scale power system failures.~~

c) Competency-based ~~-~~ — defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system*?

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

This NERC Vegetation Management Standard ("standard") uses a defense-in-depth approach to improve the reliability of the electric Transmission System by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations.

Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term "public lands" includes municipal lands, village lands, city lands, and a host of other governmental entities.

The standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

The standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.
Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

The drafting team reviewed and edited version 1 of FAC-003-1 to remove prescriptive and administrative language in order to distill the technical requirements down to their essential reliability content. ~~Text that~~ Explanatory text is ~~explanatory in nature is placed in a~~offered within two special ~~section of the standard entitled~~ sections, Background and Guideline and Technical Basis, to aid in ~~the~~ understanding ~~of~~ the standard and its requirements. ~~Furthermore,~~ Rationale text boxes and other text boxes are also inserted ~~alongside each requirement~~throughout the standard to ~~communicate~~aid understanding the sections. The Effective Dates section covers five special cases for lines that undergo specific transitions as or after the ~~foundation for~~ standard has reached the ~~requirement.~~

~~Disclaimer~~

~~This supporting document is supplemental to the reliability standard FAC-003-2 — Transmission Vegetation Management and does not contain mandatory requirements subject to compliance review.~~

general effective date.

Preface

The NERC Vegetation Management Standard Drafting Team (VM SDT) acknowledges those across the industry who contributed to the development of this Standard and companion Technical Reference document. ~~The~~This Technical Reference document is intended to provide supplemental explanatory background and guidance related to requirements contained in the Standard but does not in itself contain requirements subject to compliance review.

The ~~VM SDT believes that a well-designed and executed Transmission Vegetation Management Program (TVMP) will have few problems meeting the requirements of this Standard. While the~~ Standard requires ~~a TVMP~~ the Transmission Owner to ~~contain certain elements,~~have documentation of the maintenance strategies or procedures or processes or specifications it uses to be successful in managing vegetation. This allows the Transmission Owner to exercise substantial flexibility in designing ~~a TVMP~~its overall program to meet ~~local~~its specific needs provided ~~it~~that the Transmission Owner also meets the purpose of the Standard.

While there are many approaches to vegetation management, the VMSDT supports industry best practices contained in ANSI A300 (Part 7) – Integrated Vegetation Management (IVM) practices on Utility Rights-of-way, as well as the companion publication Best Management Practices – Integrated Vegetation Management, as an effective strategy to maintain compliance with this Standard. ANSI A300 (Part 7), approved by industry consensus in 2006, contains many elements needed for an effective ~~TVMP as required by~~vegetation management. Those elements are similar to the requirements in this Standard. One key element is the "wire zone – border zone" concept. Supported by over 50 years of continuous research, wire zone – border zone is a proven method to manage vegetation on transmission rights-of-ways and is an industry accepted best practice to help ensure electric system reliability.

The VM SDT believes that Transmission Owners who adopt and effectively implement IVM principles, particularly the "wire zone – border zone" concept, are far less likely to experience a vegetation caused outage than those who do not.

~~Definition of Terms~~Effective Dates & Special States of Transition

The first sentence of the Effective Dates section is standard language used in most NERC standards to cover the general effective date and is sufficient to cover the vast majority of situations. Five special cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the standard. The text for each of these five cases is copied from the standard and is shown below in italic font. An explanation of the need for each special exception follows each copied text section.

1. *A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.*

Case 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effective for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on the January 1 of the PY specified with an allowance of at least 12 months for the Transmission Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.

Date that Planning Study is completed	PY the line will become an IROL element	Date 1	Date 2	Effective Date The latter of Date 1 or Date 2
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

2. *A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.*

Case 2 is needed because a line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

3. *A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date*

Case 3 is needed because a line operating at 200 kV or above that once was designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.

4. *An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.*

Case 4 is needed because an existing line that is to be operated at 200 kV or above can be acquired by a Transmission Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the Transmission owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network which will thereafter make the line subject to the standard.

5. *An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.*

Case 5 is needed because an existing line that is operated below 200 kV can be acquired by a Transmission Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the Transmission owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network. In this special case the line upon acquisition was designated as an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC transfer Path.

Definition of Terms

Right-of-Way (ROW)*

-*The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.*

The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

The current NERC glossary definition of Right of Way has been modified to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of "right of way" in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

This definition does not imply that danger tree rights beyond the constructed and maintained width are incorporated in the definition; therefore fall-ins from outside the ROW but within an area with danger tree rights would not be considered fall-ins from within the ROW.

Vegetation Inspection*

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.

Current definition of Vegetation Inspection: The systematic examination of a transmission corridor to document vegetation conditions.

The inspection includes the identification of any vegetation that may pose a threat to reliability prior to the next planned maintenance or inspection work, considering the current location of the conductor and other possible locations of the conductor due to sag and sway for rated conditions.

This definition allows both maintenance inspections and vegetation inspections to be performed concurrently.

* This is a modification to a defined term in the NERC glossary and will be incorporated into the NERC glossary of terms with final approval of this standard revision.

See the Guidelines and Technical Basis section on Requirement R6 contained within the Standard for more details on inspections.

Minimum Vegetation Clearance Distance (MVCD)
The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method has been in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figures 1, 2 and 3. Details of the equations and an example calculation are provided in Appendix 1below of the Technical Reference document. Table 1in Appendix 1 below provides MVCD values for various voltages and altitudes.

Applicability of the Standard

4. Applicability

4.1. *Functional Entities:*
Transmission Owners

4.2. *Facilities:* *Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal*[1]*, state, provincial, public, private, or tribal entities:*

4.2.1 *~~Overhead~~Each overhead transmission lines operated at 200kV or higher.*

4.2.2 *~~—Overhead~~ Each overhead transmission lines operated below 200kV ~~having been~~ identified as ~~included in the definition~~an element of an ~~Interconnection Reliability Operating Limit (~~IROL~~)~~ under NERC Standard FAC~~-~~-014 by the Planning Coordinator.*

4.2.3 *~~Overhead~~Each overhead transmission lines operated below 200 kV ~~having been~~ identified as ~~included in the definition~~an element of ~~one of the~~a Major WECC Transfer Paths in the Bulk Electric System by WECC.*

4.2.4 *~~This standard applies to~~*Each overhead transmission ~~*lines*~~line identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the spa*n of the transmission line that is crossing the substation fence.*

4.3. *Enforcement:* *The reliability obligations of the applicable entities and facilities are contained within the technical requirements of this standard~~. [Straw proposal]~~*

> **Rationale**
> ~~—~~The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) ~~The standard was written for Transmission Owners. Rolling the excluded areas into this standard will bring GO and DP into the standard, even though~~ NERC has ~~an initiative~~a project in place to address ~~this bigger registry issue.~~at a later date the

In Order 693, FERC discussed the 200 kV bright-line test of applicability. While FERC did not change the 200 kV bright~~-~~-line, the Commission remained concerned that there may be some transmission lines operating at lesser voltages that could have significant impact on the Bulk Electric System that should therefore be subject to this standard.

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[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies"*.

NERC Standard FAC-014 has the stated purpose, "*To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.*" FAC-014 requires Reliability Coordinators, Planning Coordinators, and Transmission Planners to have a methodology to identify all lines that might comprise an IROL. Thus, these entities would identify sub-200 kV lines that qualify as part of an IROL and should be subject to FAC-003-2.

Although all three entities may prepare the list of elements, ~~FAC-003-2 presently does not specify that it is the~~ the list ~~from~~ as provided by the Planning Coordinator ~~that should be used by Transmission Owners~~function is the more appropriate choice for ~~FAC-003. However, the~~this Standard. The Time Horizon needed to plan vegetation management work does not lend itself to the operating horizon of a Reliability Coordinator. Additionally, the Planning Coordinator has a wider-area view than the Transmission Planner and could thus identify any elements of importance to a sub-set of its area that might be missed by a Transmission Planner.

Transmission Owners, who do not already get the list of circuits included in the definition of an IROL, can get them from the Planning Coordinator. Specifically R5 of FAC-014 specifies that "*The Reliability Coordinator, Planning Authority (Coordinator) and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits*"

Vegetation-related Sustained Outages that occur due to natural disasters are beyond the control of the Transmission Owner. These events are not classified as vegetation-related Sustained Outages and are therefore exempt from the Standard. Transmission lines are not designed to withstand the impacts of natural disasters such as flood, drought, earthquake, major storms, fire, hurricane, tornado, landslides, ice storms, etc. In the aftermath of catastrophic system damage from natural disasters the Transmission Owner's focus is on electric system restoration for public safety and critical support infrastructure.

Sustained Outages due to human or animal activity are beyond the control of the Transmission Owner. These outages are not classified as vegetation-related Sustained Outages and are therefore exempt from the Standard. Examples of these events may include new plantings by outside parties of tall vegetation under the transmission line planted since the last Vegetation Inspection, tree contacts with line initiated by vehicles, logging activities, etc.

The foregoing exemptions are addressed in a new footnote 2. Referred to collectively as force majeure events and activities, this footnote applies to requirements R1 and R2 in FAC-003-2.

The reliability objective of this NERC Vegetation Management Standard ("Standard") is to prevent vegetation-related outages which could lead to Cascading by effective vegetation maintenance while recognizing that certain outages such as those due to vandalism, human errors and acts of nature are not preventable. Operating experience clearly indicates that trees that have grown out of specification could contribute to a cascading grid failure, especially under heavy electrical loading conditions.

Serious outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. To properly reduce and manage this risk, it is necessary to apply the Standard to applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee. For the purposes of the Standard and this Technical Reference document, the term “public lands” includes municipal lands, village lands, city lands, and land owned by a host of other governmental entities.

The Standard addresses vegetation management along applicable overhead lines that serve to connect one electric station to another. However, it is not intended to be applied to lines sections inside the electric station fence or other boundary of an electric station, submarine or underground lines.

The Standard is intended to reduce the risk of Cascading involving vegetation. It is not intended to prevent customer outages from occurring due to tree contact with all transmission lines and voltages. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this Standard is not written to address such isolated situations which have little impact on the overall Bulk Electric System.

Vegetation growth is constant and always present. Unmanaged vegetation ~~poses an increased outage risk when~~below numerous transmission lines that are operating at or near their Rating~~.~~ is highly problematic. This ~~poses a significant risk of~~situation has led to multiple subsequent line failures and Cascading. ~~On the other hand~~ Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are statistically intermittent. ~~The probability of occurrence of these~~ These events ~~is~~are not ~~dependent on~~any more likely to occur during heavy system loads~~.~~ than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this Standard’s emphasis is on vegetation grow-ins.

In preparing the original vegetation management standard in 2005, industry stakeholders set the threshold for applicability of the standard at 200kV. This was because an unexpected loss of lines operating at above 200kV has a higher probability of initiating a widespread blackout or cascading outages compared with lines operating at less than 200kV.

The original NERC Standard FAC-003-1 also allowed for application of the standard to “critical” circuits (critical from the perspective of initiating widespread blackouts or cascading outages) operating below 200kV. While the percentage of these circuits is relatively low, it remains a fact that there are sub-200kV circuits whose loss could contribute to a widespread outage. Given the very limited exposure and unlikelihood of a major event related to these lower-voltage lines, it would be an imprudent use of resources to apply the Standard to all sub-200kV lines. The drafting team, after evaluating several alternatives, selected the IROL and WECC Major Transfer Path criteria to determine applicable lines below 200 kV that are subject to this standard.

Requirements R1 and R2

R1. *Each Transmission Owner shall manage vegetation to prevent encroachments* ~~**of the types shown below,**~~ *into the Minimum Vegetation Clearance Distance (MVCD) of* ~~**any of**~~ *its applicable line(s)* ~~**identified as**~~*which are either an element of an* ~~**Interconnection Reliability Operating Limit (**~~*IROL*~~**) in the planning horizon by the Planning Coordinator;**~~*,* *or an element of a Major* ~~**Western Electricity Coordinating Council (**~~*WECC*~~**) transfer path(s);**~~ *Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions*~~*.*~~ ~~[2]~~ *of the types shown below[3]:*

1. ~~*1.*~~ *An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage[4],*
2. ~~*2.*~~ *An encroachment due to a fall-in from inside the Right-of-Way (ROW)*

Rationale for R1 and R2:
Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale
~~The MVCD is a calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages. The distances in Table 2 were derived using a proven transmission design method. The~~ for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a ~~TO's~~Transmission Owner's vegetation maintenance program ~~since the encroachments listed require different~~:

1. This management failure is found by routine inspection or Fault event investigation, and ~~increasing levels~~is normally symptomatic of ~~skills~~unusual conditions in an otherwise sound program.

2. This management failure occurs when the height and ~~knowledge~~location of a side tree within the ROW is not adequately addressed by the program.

3. This management failure occurs when side

~~[2] This requirement does not apply to circumstances that are b~~ ~~this reliability standard, including natural disasters such as ea~~ ~~shear, fresh gale, major storms as defined either by the Trans~~ ~~storms, and floods; human or animal activity such as logging~~ ~~arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.~~

[3] This requirement does not apply to circumstances that are beyond the control of a Transmission Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

[4] If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

that caused a vegetation-related Sustained Outage[5],

3. ~~3.~~ *An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained* ~~**Outage**~~ *Outage*[4],

4. ~~4.~~ *An encroachment due to* ~~**a grow-in**~~ *vegetation growth into the MVCD that caused a vegetation-related Sustained* ~~**Outage.**~~ *Outage*[4]*.*

~~*[VRF – High] [Time Horizon – Real-time]*~~

R2. *Each Transmission Owner shall manage vegetation to prevent encroachments* ~~*of the types shown below,*~~ *into the MVCD* ~~*of any*~~ *of its applicable line(s)* ~~*that is*~~*which are* not *either an element of an IROL*~~*;*~~*, or an element of a Major WECC* ~~*transfer path*~~*Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions*~~*.*~~[2] *of the types shown below*[2]*:*

1. ~~1.~~ *An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained* ~~**Outage**~~ *Outage*[3],

2. ~~2.~~ *An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained* ~~**Outage**~~ *Outage*[4],

3. ~~3.~~ *An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained* ~~**Outage**~~ *Outage*[4],

4. ~~4.~~ *An encroachment due to* ~~**a grow-in**~~ *vegetation growth into the MVCD that caused a vegetation-related Sustained* ~~***Outage. [VRF – Medium] [Time Horizon – Real-time]***~~ *Outage*[4]

M1. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. ~~Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments.~~

~~If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.~~

~~Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period. (R1)~~

[5] Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

~~***M2.*** Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2.~~ Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

M2. Each~~If a later confirmation of a Fault by the~~ Transmission Owner ~~shows~~has evidence that ~~a~~it managed vegetation to prevent encroachment ~~within~~into the MVCD ~~has occurred from vegetation within the ROW, this shall be considered the equivalent~~as described in R2. Examples of acceptable forms of ~~a Real-time observation.~~

~~Multiple~~evidence may include dated attestations, dated reports containing no Sustained Outages ~~on an individual line, if caused by the same vegetation, will be reported as one outage regardless~~associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of ~~the actual number of outages within a 24-hour period.~~any MVCD encroachments. (R2)

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the prevention of vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each Transmission Owner to manage vegetation to prevent encroachment within the ~~Minimum Vegetation Clearance Distance ("~~MVCD~~")~~ of transmission lines. R1 is applicable to lines ~~"~~that are identified as an element of an ~~Interconnection Reliability Operating Limit (~~IROL~~)~~ or Major ~~Western Electricity Coordinating Council (~~WECC~~)~~ transfer path ~~(operating within Rating and Rated Electrical Operating Conditions) to avoid a Sustained Outage".~~. R2 ~~applies~~ is applicable to all other ~~applicable~~ lines that are not an element of an IROL ~~or~~, and not an element of a Major WECC Transfer Path.

The separation of applicability (between R1 and R2) recognizes that ~~an encroachment into the MVCD of an IROL or Major WECC Transfer Path transmission~~inadequate vegetation management for an applicable line that is an element of an IROL or Major WECC Transfer Path is a greater risk to the interconnected electric transmission system~~.~~ than applicable lines that are not an element of an IROL or a Major WECC Transfer Path. Applicable lines that are not an element of an IROL or Major WECC Transfer Path ~~are required to be clear of~~do require effective vegetation management, but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

~~These requirements (~~R1 and R2~~)~~ state that if vegetation encroaches within the distances in Table 1 in Appendix 1 of this supplemental ~~Transmission Vegetation Management Standard FAC-003-2~~ Technical Reference document, it is in violation of the standard. Table ~~2~~1below, which is the same as Table 2 in the standard, tabulates the distances necessary to prevent spark-over based on the Gallet equations as described more fully in Appendix 1 below.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by a Transmission Operator or Reliability Coordinator to protect an Interconnection may cause ~~the transmission line to sag more~~excessive sagging and ~~come closer to vegetation, potentially causing~~ an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not ~~a violation~~violations of ~~these requirements~~this standard.

Evidence of ~~violation of Requirement R1 and R2~~failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of ~~applicable~~the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. ~~If an investigation of~~ Faults which do not cause a ~~Fault by a Transmission Owner confirms that a~~Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD ~~occurred, then it shall be~~are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs ~~were defined~~for R1 and R2 are structured such that they directly correlate to the severity of a failure of a Transmission Owner to manage vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the ~~goal~~objective of "preventing ~~a Sustained Outage~~the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with a Transmission Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example~~, a limb~~ initial investigations and corrective actions may ~~only partially break and intermittently contact a~~not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the ~~Standard~~standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

If the TO has applicable lines operated at nominal voltage levels not listed in Table 2, then the TO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

Requirement R3

Rationale

The documentation provides a basis for evaluating the competency of the Transmission Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the Transmission Owner avoids vegetation-to-wire conflicts under all Rated Electrical Operating Conditions. See Figure 1 for an illustration of possible conductor locations.

R3. *Each Transmission Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable transmission lines that ~~include(s)~~accounts for the following:*

3.1 *~~Accounts for the movement~~Movement of applicable ~~transmission~~ line conductors under their Facility Rating and all Rated Electrical Operating Conditions;*

3.2 *~~Accounts for the inter~~Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.*

~~[VRF – Lower] [Time Horizon – Long Term Planning]~~

M3. *The maintenance strategies or procedures or processes or specifications provided demonstrate that the Transmission Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)*

Requirement R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, a Transmission Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the Transmission Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the ~~Transmission System.~~transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources and the competency of the Transmission Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the Transmission Owner must be able to ~~state what~~show the documentation of its approach ~~is~~ and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7. However, regardless of the approach a utility uses to manage vegetation, any approach a Transmission Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the Transmission Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*
4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing ~~as a~~in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation.

Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figures 1, 2, and 3 below.

Conductor Dynamics

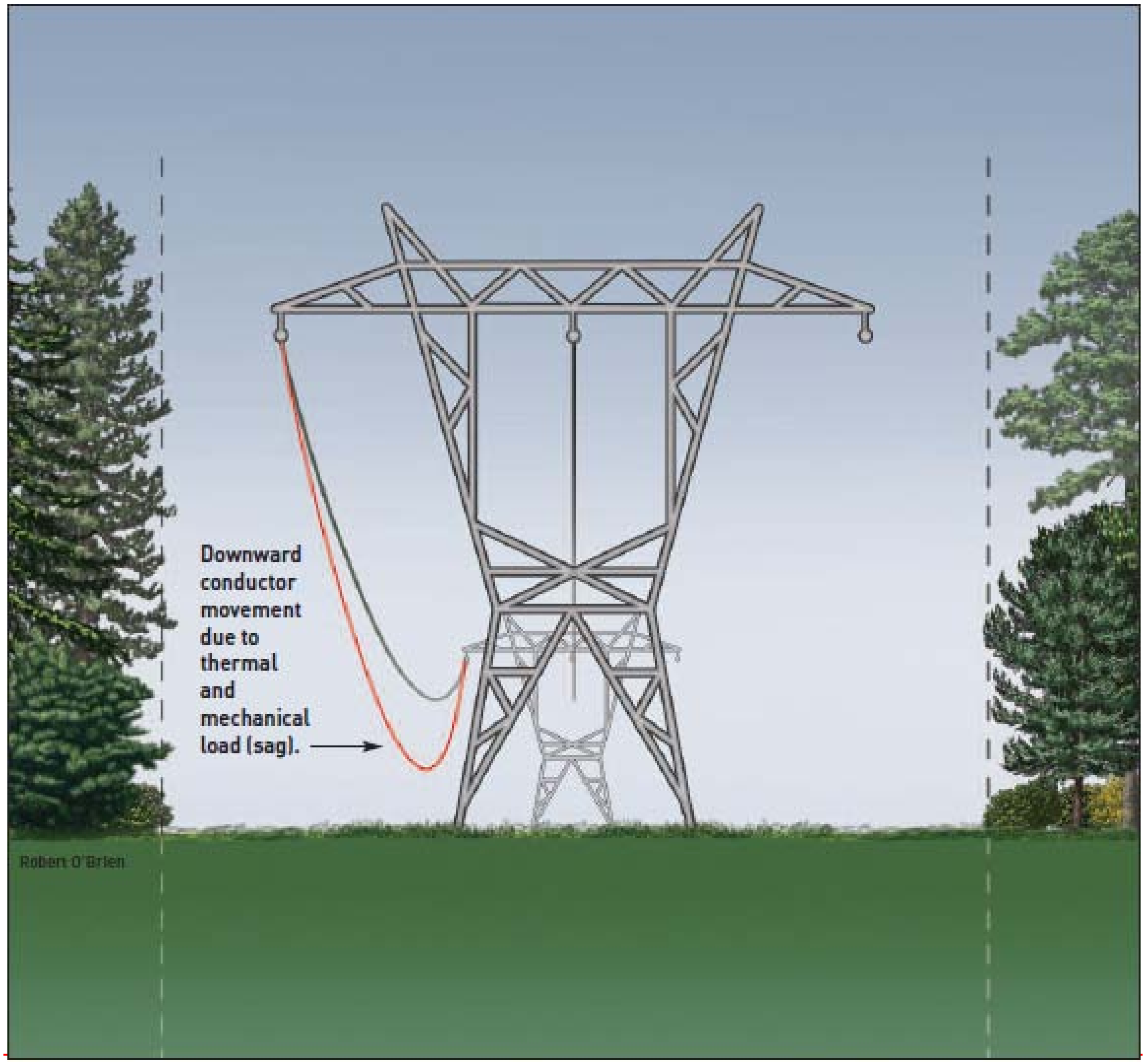
In order for a Transmission Owner to develop a specific maintenance approach, it is important to understand the dynamics of a line conductor's ~~movement.~~movements. This paper will first address the complexities inherent in observing and predicting conductor movement, particularly for field personnel. It will then present some examples of maintenance approaches which Transmission Owners may consider that take into account these complexities, ~~while resulting in~~and the practical approaches ~~for~~that can be utilized by field personnel.

Additionally, it is important the Transmission Owner consider all conductor locations, the MVCD, and vegetation growth between maintenance activities when developing a maintenance approach.

Understanding Conductor Position and Movement

The conductor's position in space at any point in time is continuously changing as a reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading.

As a consequence of these loading variables, the conductor's position in space is dynamic and moving. When calculating the range of conductor positions, the Transmission Owner should use the same design criteria and assumptions that ~~the Transmission Owner uses when establishing~~are used to establish Ratings and ~~SOL,~~System Operating Limits (SOLs), as described in other standards. Typically, the greatest conductor ~~movement would be~~movements occur at mid-span. As the conductor moves through various positions, a spark-over zone surrounding the conductor moves with it. The radius of the spark-over zone may be found by referring to Table 1 ~~("Minimum Vegetation Clearance Distances") in the standard.~~below. For illustrations of this zone and conductor movements, Figures 1 ~~through~~, 2 and 3 below ~~demonstrate these concepts.~~are provided. At the time of making a field observation, however, it is very difficult to precisely know where the conductor is in relation to its wide range of all possible positions. Therefore, Transmission Owners must adopt maintenance approaches that account for this dynamic situation.


Downward
conductor
movement
due to
thermal
and
mechanical
load (sag).
Robert O'Brien

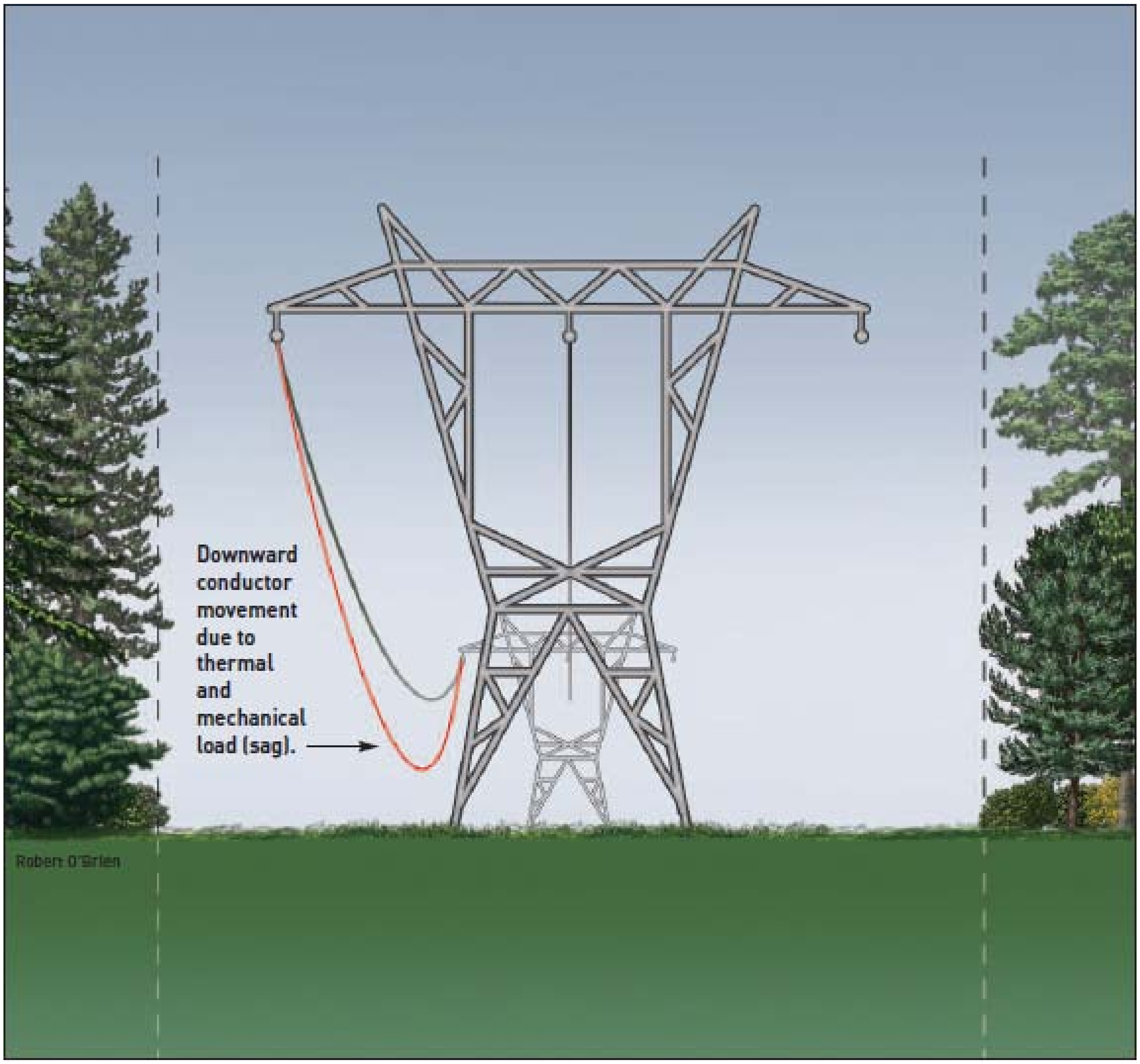
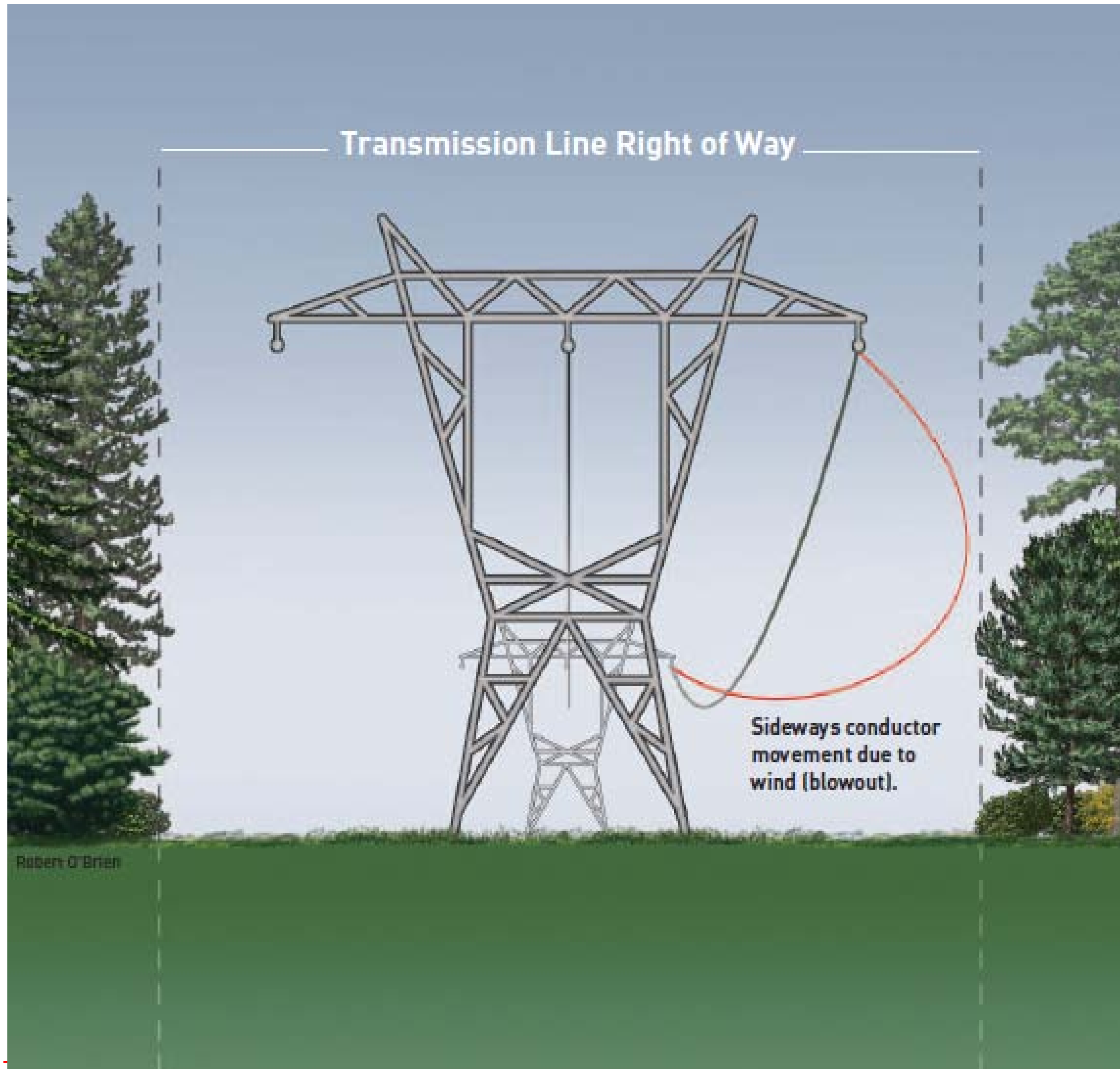

Downward conductor movement due to thermal and mechanical load (sag).
Robert O'Brien

Figure 1


Transmission Line Right of Way
Sideways conductor movement due to wind (blowout).
Robert O'Brien

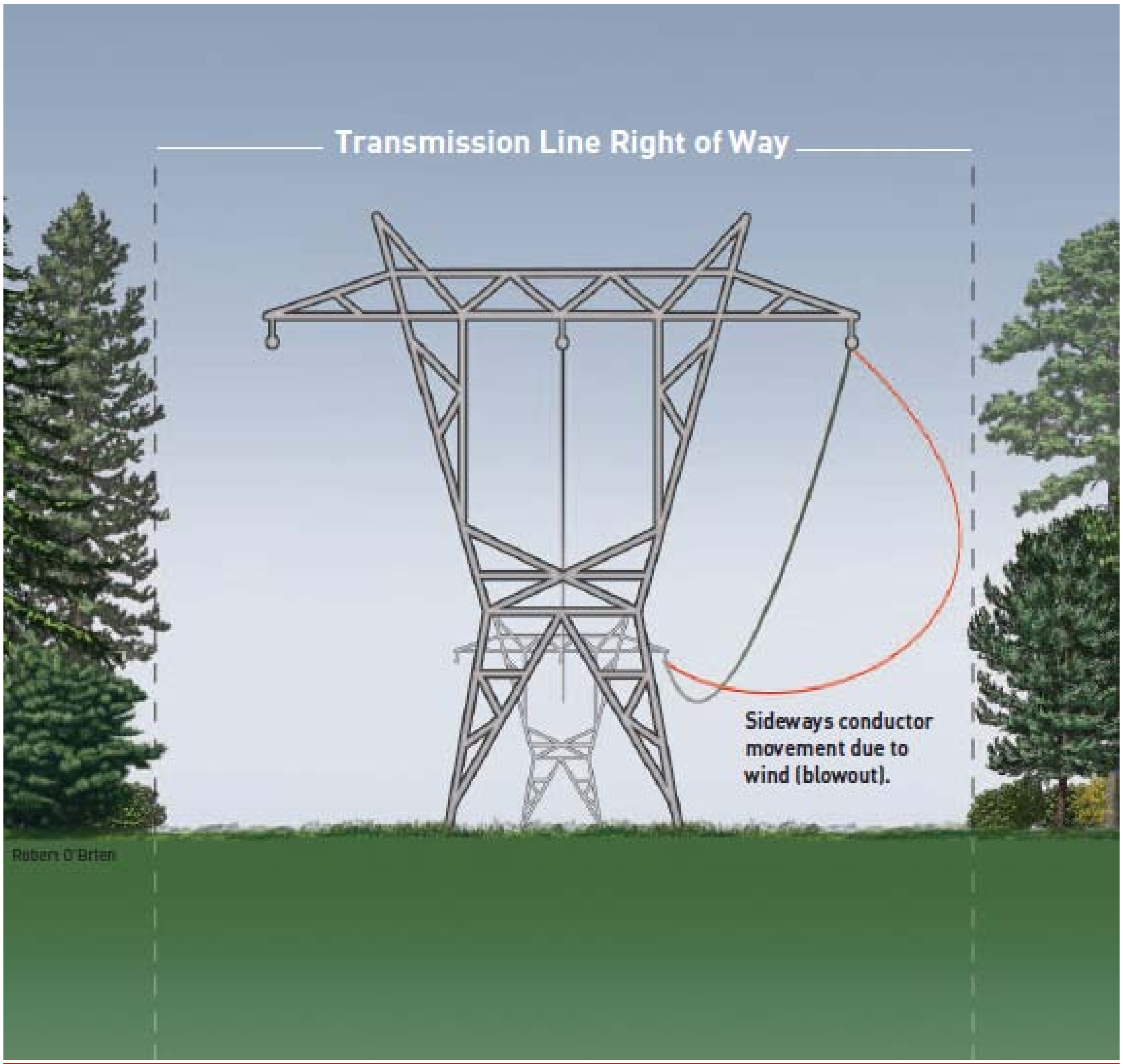
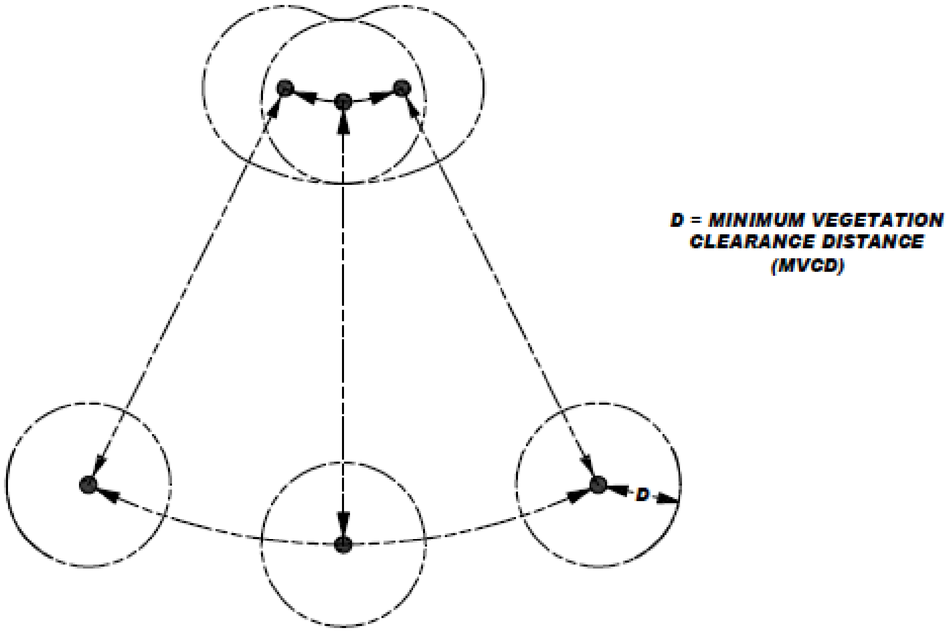

Transmission Line Right of Way
Sideways conductor movement due to wind (blowout).
Robert O'Brien

Figure 2



~~*Cross-Section View of a Single Conductor*~~

~~*At a Given Point Along The Span*~~

~~*Showing Six Possible Conductor Positions Due to Movement*~~

~~*Resulting From Thermal and Mechanical Loading*~~

~~*For Consideration in Developing a Maintenance Approach*~~

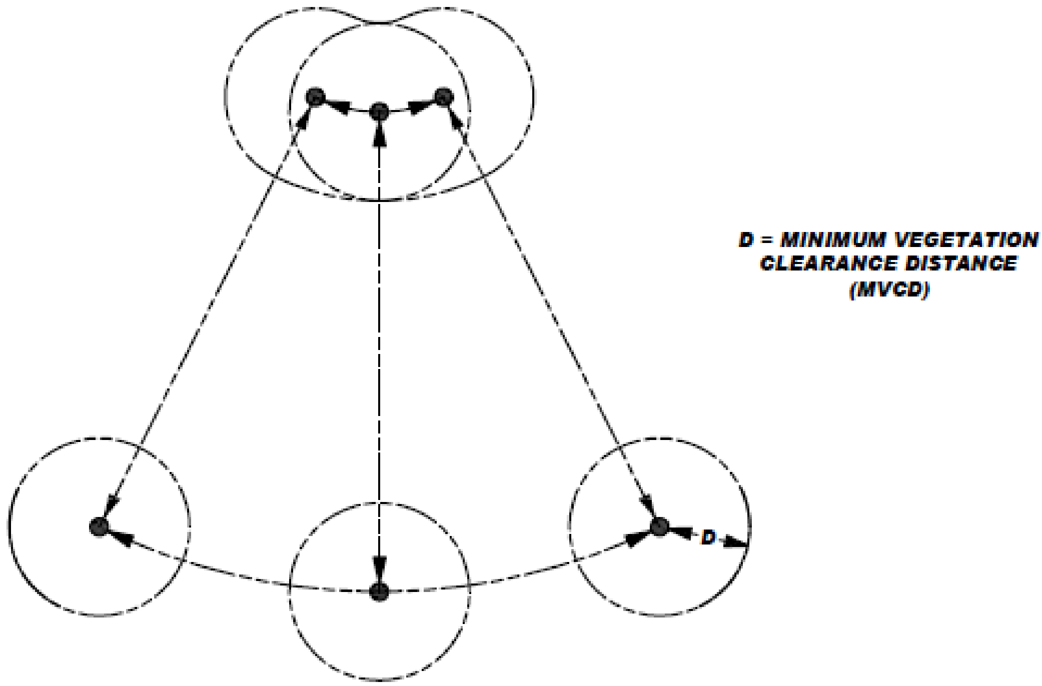


Figure 3

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

Selecting a Maintenance Approach

In order to maintain adequate separation between vegetation and transmission line conductors, the Transmission Owner must craft a maintenance strategy that keeps vegetation well away from the spark-over zone mentioned above. In fact, it is generally necessary to incorporate a variety of maintenance strategies. For example, one Transmission Owner may utilize a combination of routine cycles, traditional IVM techniques and long-term planning. Another Transmission Owner may place a higher reliance on frequent inspections and ~~quick~~follow-up remediation as opposed to a set cyclical approach. This variation of approaches is further warranted when factors, such as terrain, vegetation types, weather and climate, and any, environmental, legal ~~and~~or other land use constraints, ~~vegetation types, and climates, are~~must be considered in developing a Transmission Owner's specific approach to satisfying ~~this requirement~~R3.

The following ~~is a sample description of one combination of~~describes some strategies which may be utilized by a Transmission Owner. A Transmission Owner's basic maintenance approach in relatively flat terrain could be to remove all incompatible vegetation from the ~~right of way~~ROW if it has the right to do so and has no constraints. In mountainous terrain, however, this strategy could change to ~~one where the Transmission Owner manages~~managing vegetation based on vegetation-to-conductor clearances, since it might not be necessary to remove vegetation in a valley that is far below the conductors at maximum sag.
If faced with easement constraints ~~and assuming~~on a line design with sufficient ground clearance, the ~~Transmission Owner 's~~ approach could ~~then~~ be to allow vegetation such as fruit trees, but ~~perhaps~~ only up to a given height at maturity (~~perhaps~~for example 10 feet from the ground). If constraints cannot be overcome and if design clearances are sufficient, an exception to the Transmission Owner's 10-foot guideline might be made. ~~Finally, if the Transmission Owner has~~If an approach is chosen to ~~utilize~~manage vegetation~~ to conductor~~ based primarily on clearance ~~distance methods, the Transmission Owner~~distances it could ~~have~~include an inspection regimen ~~in place~~ to regularly ensure that~~ any~~ impending clearance problems are identified early for rectification.

ANSI A300 – Best Management Practices for Tree Care Operations

A description of ANSI A-300, part 7, is offered below to illustrate another maintenance approach that could be used in developing a comprehensive transmission vegetation management program.

Introduction

Integrated Vegetation Management (IVM) is a best management practice conveyed in the American National Standard for Tree Care Operations, Part 7 (ANSI 2006) and the International Society of Arboriculture *Best Management Practices: Integrated Vegetation Management* (Miller 2007). IVM is consistent with the requirements in FAC-003-02, and it provides practitioners with what industry experts consider to be appropriate techniques to apply to electric right-of-way projects in order to meet or exceed the Standard.

IVM is a system of managing plant communities whereby managers set objectives; identify compatible and incompatible vegetation; consider action thresholds; and evaluate, select and implement the most appropriate control method or methods to achieve set objectives. The choice of control method or methods should be based on the environmental impact and anticipated effectiveness; along with site characteristics, security, economics, current land use and other factors.

Planning and Implementation
Best management practices provide a systematic way of planning and implementing a vegetation management program. While designed primarily with transmission systems in mind, it is also applicable to distribution projects. As presented in ANSI A300 part 7 and the ISA best management practices, IVM consists of 6 elements:

1) Set Objectives
2) Evaluate the Site
3) Define Action Thresholds
4) Evaluate and Select Control Methods
5) Implement IVM
6) Monitor Treatment and Quality Assurance

The setting of objectives, defining action thresholds, and evaluating and selecting control methods all require decisions. The planning and implementation process is cyclical and continuous, because vegetation is dynamic and managers must have the flexibility to adjust their plans. Adjustments may be made at each stage as new information becomes available and circumstances evolve.

Set Objectives
Objectives should be clearly defined and documented. Examples of objectives can include promoting safety, preventing sustained outages caused by vegetation growing into electric facilities, maintaining regulatory compliance, protecting structures and security, restoring electric service during emergencies, maintaining access and clear lines of sight, protecting the environment, and facilitating cost effectiveness.

Objectives should be based on site factors, such as workload and vegetation type, in addition to human, equipment and financial resources. They will vary from utility to utility and project to project, depending on line voltage and criticality, as well as topographical, environmental, fiscal and political considerations. However, where it is appropriate, the overriding focus should be on environmentally-sound, cost effective control of species that potentially conflict with the electric facility, while promoting compatible, early successional, sustainable plant communities.

Work Load Evaluations
Work-load evaluations are inventories of vegetation that could have a bearing on management objectives. Work load assessments can capture a variety of vegetation characteristics, such as location, height, species, size and condition, hazard status, density and clearance from conductors. Assessments should be conducted considering voltage, conductor sag from ambient temperatures and loading, and the potential influence of wind on line sway.

Evaluate and Select Control Methods
Control methods are the process through which managers achieve objectives. The most suitable control method best achieves management objectives at a particular site. Many

cases call for a combination of methods. Managers have a variety of controls from which to choose, including manual, mechanical, herbicide and tree growth regulators, biological, and cultural options.

Manual Control Methods
Manual methods employ workers with hand-carried tools, including chainsaws, handsaws, pruning shears and other devices to control incompatible vegetation. The advantage of manual techniques is that they are selective and can be used where others may not be. On the other hand, manual techniques can be inefficient and expensive compared to other methods.

Mechanical Control Methods
Mechanical controls are done with machines. They are efficient and cost effective, particularly for clearing dense vegetation during initial establishment, or reclaiming neglected or overgrown right of way. On the other hand, mechanical control methods can be non-selective and disturb sensitive sites.

Tree Growth Regulator and Herbicide Control Methods
Tree growth regulators and herbicides can be effective for vegetation management. Tree growth regulators (TGRs) are designed to reduce growth rates by interfering with natural plant processes. TGRs can be helpful where removals are prohibited or impractical by reducing the growth rates of some fast-growing species.

Herbicides control plants by interfering with specific botanical biochemical pathways. Herbicide use can control individual plants that are prone to re-sprout or sucker after removal. When trees that re-sprout or sucker are removed without herbicide treatment, dense thickets develop, impeding access, swelling workloads, increasing costs, blocking lines-of-site, and deteriorating wildlife habitat. Treating suckering plants allows early successional, compatible species to dominate the right-of-way and out-compete incompatible species, ultimately reducing work.

Cultural Control Methods
Cultural methods modify habitat to discourage incompatible vegetation and establish and manage desirable, early successional plant communities. Cultural methods take advantage of seed banks of native, compatible species lying dormant on site. In the long run, cultural control is the most desirable method where it is applicable.

A cultural control known as cover-type conversion provides a competitive advantage to short-growing, early successional plants, allowing them to thrive and eventually out-compete unwanted tree species for sunlight, essential elements and water. The early successional plant community is relatively stable, tree-resistant and reduces the amount of work, including herbicide application, with each successive treatment.

Wire-Border Zone
The wire-border zone technique is a management philosophy that can be applied through cultural control. W.C. Bramble and W.R. Byrnes developed it in the mid-1980s out of research begun in 1952 on a transmission right-of-way in the Pennsylvania State Game Lands 33 Research and Demonstration project (Yahner and Hutnik (2004).

The wire zone is the section of a utility transmission right-of-way directly under the wires and extending outward about 10 feet on each side. The wire zone is managed to promote a low-growing plant community dominated by grasses, herbs and small shrubs (under 3 feet in height at maturity). The border zone is the remainder of the right-of-way. It is managed to establish small trees and tall shrubs (under 25 feet in height at maturity). When properly managed, diverse, tree-resistant plant communities develop in wire and border zones. The communities not only protect the electric facility and reduce long-term maintenance, but also enhance wildlife habitat, forest ecology and aesthetic values.

Although the wire-border zone is a best practice in many instances, it is not necessarily universally suitable. For example, standard wire-border zone prescriptions may be unnecessary where lines are high off the ground, such as across low valleys or canyons, so the technique can be modified without sacrificing reliability.

One way to accommodate variances in topography is to establish different regions based on wire height. For example, over canyon bottoms or other areas where conductors are 100 feet or more above the ground, only a few trees are likely to be tall enough to conflict with the lines. In those cases, trees that potentially interfere with the transmission lines can be removed selectively on a case-by-case basis.

In areas where the wire is lower, perhaps between 50-100 feet from the ground, a border zone community can be developed throughout the right-of-way. Note that in many cases, conductor attachment points are more than 50 feet off the ground, so a border zone community can be cultivated near structures. Where the line is less than 50 feet off the ground, managers could apply a full wire-border zone prescription.

An environmental advantage of this type of modification is stream protection. Streams often course through the valleys and canyons where lines are likely to be elevated. Leaving timber or border zone communities in canyon bottoms helps shelter this valuable habitat, enabling managers to achieve environmentally sensitive objectives.

Implement IVM

All laws and regulations governing IVM practices and specifications written by qualified vegetation managers must be followed. Integrated vegetation management control methods should be implemented on regular work schedules, which are based on established objectives and completed assessments. Work should progress systematically, using control measures determined to be best for varying conditions at specific locations along a right-of-way. Some considerations used in developing schedules include the importance and type of line, vegetation clearances, ~~work loads~~workloads, growth rate of predominant vegetation, geography, accessibility, and in some cases, time lapsed since the last scheduled work.

Clearances Following Work

Clearances following work should be sufficient to meet management objectives, including preventing trees from entering the Minimum Vegetation Clearance Distance, electric safety risks, service-reliability threats and cost.

Monitor Treatment and Quality Assurance

An effective program includes documented processes to evaluate results. Evaluations can involve quality assurance while work is underway and after it is completed. Monitoring for quality assurance should begin early to correct any possible miscommunication or misunderstanding on the part of crewmembers. Early and consistent observation and evaluation also provides an opportunity to modify the plan, if need be, in time for a successful outcome.

Utility vegetation management programs should have systems and procedures in place for documenting and verifying that vegetation management work was completed to specifications. Post-control reviews can be comprehensive or based on a statistically representative sample. This final review points back to the first step and the planning process begins again.

Summary of A-300 example

Integrated Vegetation Management offers among others, a systematic way of planning and implementing a vegetation management program as presented in ANSI A300 Part 7. This methodology enables a program to comply with the NERC *Transmission Vegetation Management Program* standard (FAC-003-2). Managers should select control options to best promote management objectives.

Vegetation Inspections

~~As with the ANSI A-300 example,~~ The ~~Transmission Owner's transmission vegetation management program (TVMP)~~standard in R6 establishes the frequency of vegetation inspections. These inspections can be used to "evaluate the site" as referred to in the second element of ANSI A300 Part 7. This necessary frequency may need to be less than the annually based ~~upon many factors. Such local and environmental factors may include~~on anticipated growth rates of the local vegetation, length of the growing season for the geographical area, limited ~~Rights of Way~~ROW width, rainfall amounts, etc.

Annual Work Plan

Requirement R7 of the Standard addresses the execution of the annual work plan. A comprehensive approach that exercises the full extent of legal rights is superior to incremental management in the long term because it reduces overall encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient at all locations on the ~~Right of Way~~ROW. Removal is superior to pruning. Removal minimizes the possibility of conflicts between energized conductors and vegetation. ~~Since~~When this is not ~~always~~ possible, the ~~Transmission Owner's~~ approach should be to use ~~its prescribed~~ vegetation maintenance methods to work towards or achieve the maximum use of the ~~Right of Way~~ROW.

Requirement R4

R4. *Each Transmission Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable transmission line when the Transmission Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment.*

Rationale
~~To~~This is to ensure expeditious communication between the Transmission Owner and the control center when a critical situation is confirmed.

~~*[VRF – Medium] [Time Horizon – Real-time]*~~

M4. *Each Transmission Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)*

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the Transmission Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of a Transmission Owner's employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The Transmission Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or positioning the system in recognition of the increasing risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some Transmission Owners may have a danger tree identification

program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5

R5. *When a Transmission Owner is constrained from performing vegetation work on an applicable line operating within their Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD ~~of its applicable transmission lines~~ prior to the implementation of the next annual work plan, then the Transmission Owner shall take corrective action to ensure continued vegetation management to prevent encroachments. ~~[VRF – Medium] [Time Horizon – Operations Planning]~~*

Rationale
Legal actions and other events may occur which result in constraints that prevent the Transmission Owner from performing planned vegetation maintenance work.
In cases where the transmission line is put at potential risk due to constraints, the intent is for the Transmission Owner to put interim measures in place, rather than do nothing.
The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

M5. *Each Transmission Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, ~~and~~or evidence that a line was de-energized. (R5)*

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the Transmission Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the Transmission Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the Transmission Owner's rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the Transmission Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the Transmission Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the Transmission Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for each location.
- In developing the specific action to mitigate the potential risk to the transmission line the Transmission Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The Transmission Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6

R6. *Each Transmission Owner shall perform a Vegetation Inspection of 100% of its applicable ~~transmission~~ lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 months between inspections on the same ROW.*[6]

~~*[VRF – Medium] [Time Horizon – Operations Planning]*~~

M6. *Each Transmission Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable ~~transmission~~ lines at least once per calendar year but with no more than 18 months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)*

Rationale
Inspections are used by Transmission Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections that fits general industry practice. In addition, the fact that Vegetation Inspections can be performed in conjunction with general line inspections further facilitates a Transmission Owner's ability to meet this requirement. However, the Transmission Owner may determine that more frequent inspections are needed to maintain reliability levels, dependent upon such factors as anticipated growth rates of the local vegetation, length of the growing season for the geographical area, limited ROW width, and rainfall amounts. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

~~The SDT~~Footnote 5 is added ~~footnote 3~~ to address the situation where a Transmission Owner through no fault of its own, would be unable to complete the vegetation inspection within the allotted time period. This would include the situation of mutual aid as well as disasters to the Transmission Owner's own system.

The VSL for Requirement R6 has VSL categories ranked by the percentage of the required ROW inspections completed. To calculate the percentage of inspection completion, the Transmission Owner may choose units such as: line miles or kilometers, circuit miles or kilometers, pole line miles, ROW miles, etc.

[6] When the Transmission Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO is granted a time extension that is equivalent to the duration of the time the TO was prevented from performing the Vegetation Inspection.

For example, when a Transmission Owner operates 2,000 miles of ~~230 kV~~applicable transmission lines this Transmission Owner will be responsible for inspecting all the 2,000 miles of ~~230 kV transmission~~ lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%. ~~The "Low VSL" for R6 would apply in this example.~~

The “Low VSL” for R6 would apply in this example.

Requirement R7

Rationale
This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. ~~An annual vegetation work plan~~It allows ~~for work~~modifications to ~~be modified~~the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that ~~the changes~~those modifications do not ~~violate the~~put the

R7. *Each Transmission Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not ~~put the transmission system at risk~~allow encroachment of ~~a~~ vegetation ~~encroachment~~into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include:*

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of a Transmission Owner[7]
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

  ~~[VRF – Medium] [Time Horizon – Operations Planning]~~

M7. *Each Transmission Owner has evidence that it completed its annual vegetation work plan. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (including modifications if any), dated work orders, dated invoices, or dated inspection records. (R7)*

R7 is a risk-based requirement. The Transmission Owner is required to implement ~~an annual~~its work plan for vegetation management to accomplish the purpose of this Standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The

[7] ~~circumstances~~Circumstances that are beyond the control of a Transmission Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or an applicable regulatory body~~, ice storms, and floods; arboricultural, horticultural or agricultural activities~~.

annual work plan requirement is not intended to necessarily require a "span-by-span", or even a "line-by-line" detailed description of all work to be performed. It is only intended to require that the Transmission Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

For example, when a Transmission Owner identifies 1,000 miles of applicable transmission lines to be completed in the TO's annual plan, the Transmission Owner will be responsible completing those identified miles. If a TO makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be: 1000 – 100 (deferred miles) = 900 modified annual plan, or 900 / 900 = 100% completed annual miles. If a TO only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: 1000 – 875 = 125 miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the Transmission Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance or work may be deferred to a subsequent year because of slower-than-expected growth. This situation may also include complying with mutual assistance agreements by moving resources off the Transmission Owner's system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan. Modifications to the annual work plan must always ensure the reliability of the electric Transmission system.

In general, the vegetation management maintenance approach should use the full extent of the Transmission Owner's legal rights on the ROW. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management in the long term because it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan~~,~~ the Transmission Owner should allow time for ~~reasonable and predictable~~ procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases~~,~~ the lead time for obtaining permits may necessitate preparing work plans more than a year prior to ~~the~~work start ~~of work.~~dates. Transmission Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the Transmission Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs and walk-through reports.

Appendix 1: Clearance Distance Derivation by the Gallet Equation

The Gallet Equation is a well-known method of computing the required strike distance for proper insulation coordination, and has the ability to take into account various air gap geometries, as well as non-standard atmospheric conditions. When the Gallet Equation and conservative probabilistic methods are combined, i.e. deterministic design, ~~sparkover~~spark-over probabilities of 10^{-6} or less are achieved. This approach is well known for its conservatism and was used to design the first 500 kV and 765 kV lines in North America [1]. Thus, the deterministic design approach using the Gallet Equation is used for the standard to compute the minimum strike distance between transmission lines and the vegetation that may be present in or along the transmission corridor.

Method Explanation (Gallet Equation)

In 1975 G. Gallet published a benchmark paper that provided a method to compute the critical flashover voltage (CFO) of various air gap geometries [4]. The Gallet Equation uses various "gap factors" to take into account various air gap geometries. Various gap factor values are provided in [1]. If the vegetation in a transmission corridor, e.g. a tree, is assumed electrically to be a large structure then the CFO of such an air gap geometry can be computed for dry or wet conditions using a well established equation proposed by Gallet [1],[2],[4],

$$CFO_A = k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} \qquad (1)$$

where,

k_w	is defined as the factor that takes into account wet or dry conditions (dry = 1.0 and wet = 0.96) and phase arrangement (multiply by 1.08 for outside phase), e.g. outside phase and wet conditions = (0.96)(1.08) = 1.037,
k_g	is defined as the gap factor (1.3 for conductor to large structure),
D	is the strike distance (m),
CFO_A	is the CFO for the relative air density (kV).
δ	is defined as the relative air density and is approximately equal to (2) where A is the altitude in km,

$$\delta = e^{-\frac{A}{8.6}} \qquad (2)$$

$$m = 1.25G_0\left(G_0 - 0.2\right) \qquad (3)$$

$$G_0 = \frac{CFO_s}{500 \cdot D} \qquad (4)$$

$$CFO_S = k_w \cdot k_g \cdot \frac{3400}{1+\frac{8}{D}} \tag{5}$$

where CFO_S is the CFO for standard atmospheric conditions (kV). Using (1)-(5), the required CFO_A can be computed using an iterative process.

Once the CFO_A is known, deterministic methods can be used to determine the required clearance distance. If we let the maximum switching overvoltage be equal to the withstand voltage of the air gap (CFO_A - 3σ) then the CFO_A can be written as (6).

$$CFO_A = \frac{V_m}{1-3\left(\frac{\sigma}{CFO_A}\right)} \tag{6}$$

where

V_m is equal to the maximum switching overvoltage, i.e. the value that has a 0.135% chance of being exceeded,

σ is the standard deviation of the air gap insulation,

CFO_A is the critical flashover voltage of the air gap insulation under non-standard atmospheric conditions.

The ratio of σ to the CFO_A given in (6) can be assumed to be 0.05 (5%) [1]. Thus, (6) can be written as (7).

$$CFO_A = \frac{V_m}{0.85} \tag{7}$$

Substituting (7) into (1) we arrive at (8).

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} \tag{8}$$

Equation 8 relates the maximum transient overvoltage, V_m, to the air gap distance, D. Using (8) to compute the required clearance distance for the specified air gap geometry (conductor to large structure) results in a probability of flashover in the range of 10^{-6}.

Transient Overvoltage

In general, the worst case transient overvoltages occurring on a transmission line are caused by energizing or re-energizing the line with the latter being the extreme case if trapped charge is present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to sparkover from the line conductor to nearby vegetation. Thus, the worst case scenarios that are typically analyzed for insulation coordination purposes (e.g. line energization and re-energization) can be ignored. For the purposes of FAC-003-2, the worst case transient overvoltage then becomes the maximum value that can occur with the line energized. Determining a realistic value of transient overvoltage for this situation is difficult because the maximum transient overvoltage factors listed in the literature are based on a

switching operation of the line in question. In other words, these maximum overvoltage values (e.g. the values listed in [2], [3] and [5]) are based on the assumption that the subject line is being energized, re-energized or de-energized. These operations, by their very nature, will create the largest transient overvoltages. Typical values of transient overvoltages of in-service lines, as such, are not readily available in the literature because the resulting level of overvoltage is negligible compared with the maximum (e.g. re-energizing a transmission line with trapped charge). A conservative value for the maximum transient overvoltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 p.u.[2]. This value is a conservative estimate of the transient overvoltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without a pre-insertion device (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. 362 kV), the maximum transient overvoltage of an "in-service" ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 p.u. or less [2]. It is well known that these theoretical transient overvoltages will not be experienced at locations remote from the bus at which they were created; however, in order to be conservative, it will be assumed that all nearby ac lines are subjected to this same level of overvoltage. Thus, a maximum transient overvoltage factor of 2.0 p.u. for ~~242~~302 kV and below and 1.4 p.u. for ac transmission lines 362 kV and above is used to compute the required clearance distances for vegetation management purposes.

The overvoltage characteristics of dc transmission lines vary somewhat from their ac counterparts. The referenced empirically derived transient overvoltage factor used to calculate the minimum clearance distances from dc transmission lines to vegetation for the purpose of FAC-003-2 will be 1.8 p.u.[3].

Example Calculation

An example calculation is presented below using the proposed method of computing the vegetation clearance distances. It is assumed that the line in question has a maximum operating voltage of 550 kV_{rms} line-to-line. Using a per unit transient overvoltage factor of 1.4, the result is a peak transient voltage of 629 kV_{crest}. It is further assumed that the line in question operates at a maximum altitude of 7000 feet (2.134 km) above sea level.

The required withstand voltage of the air gap must be equal to or greater than 629 kV_{crest}. Since the altitude is above sea level, (1) - (5) have to be iterated on to achieve the desired result. Equation (9) can be used as an initial guess for the clearance distance.

$$D_i = \frac{8}{\dfrac{3400 \cdot k_w \cdot k_g}{\left(\dfrac{V_m}{0.85}\right)} - 1} \tag{9}$$

For our case here, V_m is equal to 629 kV, k_w = 1.037 and k_g = 1.3. Thus,

$$D_i = \frac{8}{\dfrac{3400 \cdot k_w \cdot k_g}{\left(\dfrac{V_m}{0.85}\right)} - 1} = \frac{8}{\dfrac{3400 \cdot 1.037 \cdot 1.3}{\left(\dfrac{629}{0.85}\right)} - 1} = 1.535m \tag{10}$$

Using (2)-(5) and (8) the withstand voltage of the air gap is next computed. This value will then be compared to the maximum transient overvoltage.

$$CFO_S = k_w \cdot k_g \cdot \frac{3400}{1+\frac{8}{D}} = 1.037 \cdot 1.3 \cdot \frac{3400}{1+\frac{8}{1.535}} = 737.7kV \quad (11)$$

$$\delta = e^{-\frac{A}{8.6}} = e^{-\frac{2.134}{8.6}} = 0.78 \quad (12)$$

$$G_O = \frac{CFO_S}{500 \cdot D} = \frac{737.7}{(500)\cdot(1.535)} = 0.961 \quad (13)$$

$$m = 1.25 \cdot G_O (G_O - 0.2) = 1.25 \cdot 0.961(0.961 - 0.2) = 0.915 \quad (14)$$

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} = (0.85)(1.037)(1.3)(0.78)^{0.915}\left(\frac{3400}{1+\frac{8}{1.535}}\right) = 499.8kV \quad (15)$$

The calculated V_m is less than 629 kV; thus, the clearance distance must be increased. A few iterations using (2)-(5) and (8) are required until the computed $V_m \geq 629$ kV. For this case it was found that D = 1.978 m (6.49 feet) yielded V_m = 629.3 kV. Using this clearance distance the following values were computed for the final iteration.

$$CFO_S = k_w \cdot k_g \cdot \frac{3400}{1+\frac{8}{D}} = 1.037 \cdot 1.3 \cdot \frac{3400}{1+\frac{8}{1.978}} = 908.5kV \quad (16)$$

$$\delta = e^{-\frac{A}{8.6}} = e^{-\frac{2.134}{8.6}} = 0.78 \quad (17)$$

$$G_O = \frac{CFO_S}{500 \cdot D} = \frac{908.5}{(500)\cdot(1.978)} = 0.919 \quad (18)$$

$$m = 1.25 \cdot G_O (G_O - 0.2) = 1.25 \cdot 0.919(0.919 - 0.2) = 0.825 \quad (19)$$

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} = (0.85)(1.037)(1.3)(0.78)^{0.825}\left(\frac{3400}{1+\frac{8}{1.978}}\right) = 629.3kV \quad (20)$$

Therefore, the minimum vegetation clearance distance for a maximum line to line ac operating voltage of 550 kV at 7000 feet above sea level is 1.978 m (6.49 feet). Table 1 provides calculated distances for various altitudes and maximum system operating ac voltages.

TABLE 1 — Minimum Vegetation Clearance Distances (MVCD)[9]
For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage ~~(kV)~~(KV)	(AC) Maximum System Voltage (kV)[10]	MVCD (feet ~~(meters)~~) ~~sea level~~ Over sea level up to 500 ft	MVCD (feet) Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet ~~(meters) 3,000ft (914.4m)~~ Over 2000 ft up to 3000 ft	MVCD feet ~~(meters) 4,000ft (1219.2m)~~ Over 3000 ft up to 4000 ft	MVCD feet ~~(meters) 5,000ft (1524m)~~ Over 4000 ft up to 5000 ft	MVCD feet ~~(meters) 6,000ft (1828.8m)~~ Over 5000 ft up to 6000 ft	MVCD feet ~~(meters) 7,000ft (2133.6m)~~ Over 6000 ft up to 7000 ft	MVCD feet ~~(meters) 8,000ft (2438.4m)~~ Over 7000 ft up to 8000 ft	MVCD feet ~~(meters) 9,000ft (2743.2m)~~ Over 8000 ft up to 9000 ft	MVCD feet ~~(meters) 10,000ft (3048m)~~ Over 9000 ft up to 10000 ft	MVCD feet ~~(meters) 11,000ft (3352.8m)~~ Over 10000 ft up to 11000 ft
765	800	8.~~06ft (2.46m)~~ 2ft	8.33ft	8.61ft	8.89ft ~~(2.71m)~~	9.17ft ~~(2.80m)~~	9.45ft ~~(2.88m)~~	9.73ft ~~(2.97m)~~	10.01ft ~~(3.05m)~~	10.29ft ~~(3.14m)~~	10.57ft ~~(3.22m)~~	10.85ft ~~(3.31m)~~	11.13ft ~~(3.39m)~~
500	550	5.~~06ft (1.54m)~~ 15ft	5.25ft	5.45ft	5.66ft ~~(1.73m)~~	5.86ft ~~(1.79m)~~	6.07ft ~~(1.85m)~~	6.28ft ~~(1.91m)~~	6.49ft ~~(1.98m)~~	6.7ft ~~(2.04m)~~	6.92ft ~~(2.11m)~~	7.13ft ~~(2.17m)~~	7.35ft ~~(2.24m)~~
345	362	3.~~12ft (0.95m)~~ 19ft	3.26ft	3.39ft	3.53ft ~~(1.08m)~~	3.67ft ~~(1.12m)~~	3.82ft ~~(1.16m)~~	3.97ft ~~(1.21m)~~	4.12ft ~~(1.26m)~~	4.27ft ~~(1.30m)~~	4.43ft ~~(1.35m)~~	4.58ft ~~(1.40m)~~	4.74ft ~~(1.44m)~~
287	302	3.88ft	3.96ft	4.12ft	4.29ft	4.45ft	4.62ft	4.79ft	4.97ft	5.14ft	5.32ft	5.50ft	5.68ft
230	242	~~2.97ft (0.91m)~~ 3.03ft	3.09ft	3.22ft	3.36ft ~~(1.02m)~~	3.49ft ~~(1.06m)~~	3.63ft ~~(1.11m)~~	3.78ft ~~(1.15m)~~	3.92ft ~~(1.19m)~~	4.07ft ~~(1.24m)~~	4.22ft ~~(1.29m)~~	4.37ft ~~(1.33m)~~	4.53ft ~~(1.38m)~~
161*	169	~~2ft (0.61m)~~ 2.05ft	2.09ft	2.19ft	2.28ft ~~(0.69m)~~	2.38ft ~~(0.73m)~~	2.48ft ~~(0.76m)~~	2.58ft ~~(0.79m)~~	2.69ft ~~(0.82m)~~	2.8ft ~~(0.85m)~~	2.91ft ~~(0.89m)~~	3.03ft ~~(0.92m)~~	3.14ft ~~(0.96m)~~
138*	145	1.~~7ft (0.52m)~~	1.78ft	1.86ft	1.94ft ~~(0.59m)~~	2.03ft ~~(0.62m)~~	2.12ft ~~(0.65m)~~	2.21ft ~~(0.67m)~~	2.3ft ~~(0.70m)~~	2.4ft ~~(0.73m)~~	2.49ft ~~(0.76m)~~	2.59ft ~~(0.79m)~~	2.7ft ~~(0.82m)~~

[9] The distances in this Table are the minimums required to prevent ~~Flashover~~Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[10] Where applicable lines are operated at nominal voltages other than those listed, The Transmission Owner should use the maximum system voltage to determine the appropriate clearance for that line.

		74ft											
115*	121	1.~~41ft (0.43m)~~44ft	1.47ft	1.54ft	1.61ft ~~(0.49m)~~	1.68ft ~~(0.51m)~~	1.75ft ~~(0.53m)~~	1.83ft ~~(0.56m)~~	1.91ft ~~(0.58m)~~	1.99ft ~~(0.61m)~~	2.07ft ~~(0.63m)~~	2.16ft ~~(0.66m)~~	2.25ft ~~(0.69m)~~
88*	100	1.~~15ft (0.35m)~~18ft	1.21ft	1.26ft	1.32ft ~~(0.40m)~~	1.38ft ~~(0.42m)~~	1.44ft ~~(0.44m)~~	1.5ft ~~(0.46m)~~	1.57ft ~~(0.48m)~~	1.64ft ~~(0.50m)~~	1.71ft ~~(0.52m)~~	1.78ft ~~(0.54m)~~	1.86ft ~~(0.57m)~~
69*	72	0.~~82ft (0.25m)~~84ft	0.86ft	0.90ft	0.94ft ~~(0.29m)~~	0.99ft ~~(0.30m)~~	1.03ft ~~(0.31m)~~	1.08ft ~~(0.33m)~~	1.13ft ~~(0.34m)~~	1.18ft ~~(0.36m)~~	1.23ft ~~(0.37m)~~	1.28ft ~~(0.39m)~~	1.34ft ~~(0.41m)~~

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above).

TABLE 1 (CONT~~.)~~) — Minimum Vegetation Clearance Distances (MVCD) [7]
For ~~Direct~~Alternating Current Voltages (meters)

(~~DC~~) AC) Nominal ~~Pole to Ground~~ System Voltage (KV) ~~(kV)~~	(AC) Maximum System Voltage (kV) [8]	MVCD ~~feet (~~meters~~)~~ ~~sea level~~	MVCD meters	MVCD meters	MVCD ~~feet~~ ~~(~~meters~~)~~ ~~3,000ft (914.4m) Alt.~~	MVCD ~~feet~~ ~~(~~meters~~)~~ ~~4,000ft (1219.2m) Alt.~~	MVCD ~~feet (~~meters~~)~~ ~~5,000ft (1524m) Alt.~~	MVCD ~~feet~~ ~~(~~meters~~)~~ ~~6,000ft (1828.8m) Alt.~~	MVCD ~~feet (~~meters~~)~~ ~~7,000ft (2133.6m) Alt.~~	MVCD ~~feet (~~meters~~)~~ ~~(8,000ft (2438.4m) Alt.~~	MVCD ~~feet (~~meters~~)~~ ~~9,000ft (2743.2m) Alt.~~	MVCD ~~feet (~~meters~~)~~ ~~10,000ft (3048m) Alt.~~	MVCD ~~feet~~ ~~(~~meters~~)~~ ~~11,000ft (3352.8m) Alt.~~
~~±750~~		~~13.92ft (4.24m)~~ Over sea level up to 152.4m	Over 152.4m up to 304.8m	Over 304.8m up to 609.6m	~~15.07ft (4.59m)~~ Over 609.6m up to 914.4m	~~15.45ft (4.71m)~~ Over 914.4m up to 1219.2m	~~15.82ft (4.82m)~~ Over 1219.2m up to 1524m	~~16.2ft (4.94m)~~ Over 1524 m up to 1828.8m	~~16.55ft (5.04m)~~ Over 1828.8m up to 2133.6m	~~16.9ft (5.15m)~~ Over 2133.6m up to 2438.4m	~~17.27ft (5.26m)~~ Over 2438.4m up to 2743.2m	~~17.62ft (5.37m)~~ Over 2743.2m up to 3048m	~~17.97ft (5.48m)~~ Over 3048m up to 3352.8m
~~±600~~		~~10.07ft (3.07m)~~			~~11.04ft (3.36m)~~	~~11.35ft (3.46m)~~	~~11.66ft (3.55m)~~	~~11.98ft (3.65m)~~	~~12.3ft (3.75m)~~	~~12.62ft (3.85m)~~	~~12.92ft (3.94m)~~	~~13.24ft (4.04m)~~	~~(13.54ft 4.13m)~~
~~±500~~765	800	~~7.89ft (~~2.~~40m)~~49m	2.54m	2.62m	~~8.71ft (~~2.~~65m)~~71m	~~8.99ft (~~2.~~74m)~~80m	~~9.25ft (~~2.~~82m)~~88m	~~9.55ft (~~2.~~91m)~~97m	~~9.82ft (2.99m)~~3.05m	~~10.1ft (~~3.~~08m)~~14m	~~10.38ft (~~3.~~16m)~~22m	~~10.65ft (~~3.~~25m)~~31m	~~10.92ft (~~3.~~33m)~~39m
~~±400~~500	550	~~4.78ft (~~1.~~46m)~~57m	1.6m	1.66m	~~5.35ft (~~1.~~63m)~~73m	~~5.55ft (~~1.~~69m)~~79m	~~5.75ft (~~1.~~75m)~~85m	~~5.95ft (~~1.~~81m)~~91m	~~6.15ft (~~1.~~87m)~~98m	~~6.36ft (1.94m)~~2.04m	~~6.57ft (~~2.~~00m)~~11m	~~6.77ft (~~2.~~06m)~~17m	~~6.98ft (~~2.~~13m)~~24m
~~±250~~345	362	~~3.43ft (1.05m)~~0.97m	0.99m	1.03m	~~4.02ft (~~1.~~23m)~~08m	~~4.02ft (~~1.~~23m)~~12m	~~4.18ft (~~1.~~27m)~~16m	~~4.34ft (~~1.~~32m)~~21m	~~4.5ft (~~1.~~37m)~~26m	~~4.66ft (~~1.~~42m)~~30m	~~4.83ft (~~1.~~47m)~~35m	~~5ft (~~1.~~52m)~~40m	~~5.17ft (~~1.~~58m)~~44m
287	302	1.18m	0.88m	1.26m	1.31m	1.36m	1.41m	1.46m	1.51m	1.57m	1.62m	1.68m	1.73m
230	242	0.92m	0.94m	0.98m	1.02m	1.06m	1.11m	1.15m	1.19m	1.24m	1.29m	1.33m	1.38m
161*	169	0.62m	0.64m	0.67m	0.69m	0.73m	0.76m	0.79m	0.82m	0.85m	0.89m	0.92m	0.96m
138*	145	0.53m	0.54m	0.57m	0.59m	0.62m	0.65m	0.67m	0.70m	0.73m	0.76m	0.79m	0.82m
115*	121	0.44m	0.45m	0.47m	0.49m	0.51m	0.53m	0.56m	0.58m	0.61m	0.63m	0.66m	0.69m

88*	100	0.36m	0.37m	0.38m	0.40m	0.42m	0.44m	0.46m	0.48m	0.50m	0.52m	0.54m	0.57m
69*	72	0.26m	0.26m	0.27m	0.29m	0.30m	0.31m	0.33m	0.34m	0.36m	0.37m	0.39m	0.41m

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

TABLE 1 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[7]
For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV) Over sea level up to 500 ft (Over sea level up to 152.4 m)	(DC) Nominal Pole to Ground Voltage (kV) Over 500 ft up to 1000 ft (Over 152.4 m up to 304.8 m	(DC) Nominal Pole to Ground Voltage (kV) Over 1000 ft up to 2000 ft (Over 304.8 m up to 609.6m)	(DC) Nominal Pole to Ground Voltage (kV) Over 2000 ft up to 3000 ft (Over 609.6m up to 914.4m	(DC) Nominal Pole to Ground Voltage (kV) Over 3000 ft up to 4000 ft (Over 914.4m up to 1219.2m	(DC) Nominal Pole to Ground Voltage (kV) Over 4000 ft up to 5000 ft (Over 1219.2m up to 1524m	(DC) Nominal Pole to Ground Voltage (kV) Over 5000 ft up to 6000 ft (Over 1524 m up to 1828.8 m)	(DC) Nominal Pole to Ground Voltage (kV) Over 6000 ft up to 7000 ft (Over 1828.8m up to 2133.6m)	(DC) Nominal Pole to Ground Voltage (kV) Over 7000 ft up to 8000 ft (Over 2133.6m up to 2438.4m)	(DC) Nominal Pole to Ground Voltage (kV) Over 8000 ft up to 9000 ft (Over 2438.4m up to 2743.2m)	(DC) Nominal Pole to Ground Voltage (kV) Over 9000 ft up to 10000 ft (Over 2743.2m up to 3048m)	(DC) Nominal Pole to Ground Voltage (kV) Over 10000 ft up to 11000 ft (Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

List of Acronyms and Abbreviations

ANSI	American National Standards Institute
IEEE	Institute of Electrical and Electronics Engineers
IVM	Integrated Vegetation Management
NERC	North American Electric Reliability Corporation

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Results-based Initiative Ad Hoc Group. *Acceptance Criteria of a Reliability Standard.*

A. Introduction

1. **Title:** **Transmission Vegetation Management Program**

2. **Number:** FAC-003-1

3. **Purpose:** To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional Reliability Organizations (RRO) and the North American Electric Reliability Council (NERC).

4. **Applicability:**

   4.1. Transmission Owner.

   4.2. Regional Reliability Organization.

   4.3. This standard shall apply to all transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RRO as critical to the reliability of the electric system in the region.

5. **Effective Dates:**

   5.1. One calendar year from the date of adoption by the NERC Board of Trustees for Requirements 1 and 2.

   5.2. Sixty calendar days from the date of adoption by the NERC Board of Trustees for Requirements 3 and 4.

B. Requirements

R1. The Transmission Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the Transmission Owner's objectives, practices, approved procedures, and work specifications[1].

R1.1. The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the Transmission Owner's transmission lines.

R1.2. The Transmission Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the Transmission Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

R1.2.1. Clearance 1 — The Transmission Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner plans to return for future

[1] ANSI A300, Tree Care Operations – Tree, Shrub, and Other Woody Plant Maintenance – Standard Practices, while not a requirement of this standard, is considered to be an industry best practice.

vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

R1.2.2. Clearance 2 — The Transmission Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These Transmission Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

R1.2.2.1 Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

R1.2.2.2 Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

R1.3. All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner, to perform their duties.

R1.4. Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

R1.5. Each Transmission Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

R2. The Transmission Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

R3. The Transmission Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission Owner to have been caused by vegetation.

R3.1. Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24-hour period.

R3.2. The Transmission Owner is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).

R3.3. The outage information provided by the Transmission Owner to the RRO, or the RRO's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.

R3.4. An outage shall be categorized as one of the following:

R3.4.1. Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;

R3.4.2. Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;

R3.4.3. Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

R4. The RRO shall report the outage information provided to it by Transmission Owner's, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the RRO as a result of any of the reported outages.

C. Measures

M1. The Transmission Owner has a documented TVMP, as identified in Requirement 1.

M1.1. The Transmission Owner has documentation that the Transmission Owner performed the vegetation inspections as identified in Requirement 1.1.

M1.2. The Transmission Owner has documentation that describes the clearances identified in Requirement 1.2.

M1.3. The Transmission Owner has documentation that the personnel directly involved in the design and implementation of the Transmission Owner's TVMP hold the qualifications identified by the Transmission Owner as required in Requirement 1.3.

M1.4. The Transmission Owner has documentation that it has identified any areas not meeting the Transmission Owner's standard for vegetation management and any mitigating measures the Transmission Owner has taken to address these deficiencies as identified in Requirement 1.4.

M1.5. The Transmission Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.

M2. The Transmission Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.

M3. The Transmission Owner has documentation that it has supplied quarterly outage reports to the RRO, or the RRO's designee, as identified in Requirement 3.

M4. The RRO has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

RRO

NERC

1.2. Compliance Monitoring Period and Reset

One calendar Year

1.3. Data Retention

Five Years

1.4. Additional Compliance Information

The Transmission Owner shall demonstrate compliance through self-certification submitted to the compliance monitor (RRO) annually that it meets the requirements of NERC Reliability Standard FAC-003-1. The compliance monitor shall conduct an on-site audit every five years or more frequently as deemed appropriate by the compliance monitor to review documentation related to Reliability Standard FAC-003-1. Field audits of ROW vegetation conditions may be conducted if determined to be necessary by the compliance monitor.

2. Levels of Non-Compliance

2.1. Level 1:

2.1.1. The TVMP was incomplete in one of the requirements specified in any subpart of Requirement 1, or;

2.1.2. Documentation of the annual work plan, as specified in Requirement 2, was incomplete when presented to the Compliance Monitor during an on-site audit, or;

2.1.3. The RRO provided an outage report to NERC that was incomplete and did not contain the information required in Requirement 4.

2.2. Level 2:

2.2.1. The TVMP was incomplete in two of the requirements specified in any subpart of Requirement 1, or;

2.2.2. The Transmission Owner was unable to certify during its annual self-certification that it fully implemented its annual work plan, or documented deviations from, as specified in Requirement 2.

2.2.3. The Transmission Owner reported one Category 2 transmission vegetation-related outage in a calendar year.

2.3. Level 3:

2.3.1. The Transmission Owner reported one Category 1 or multiple Category 2 transmission vegetation-related outages in a calendar year, or;

2.3.2. The Transmission Owner did not maintain a set of clearances (Clearance 2), as defined in Requirement 1.2.2, to prevent flashover between vegetation and overhead ungrounded supply conductors, or;

2.3.3. The TVMP was incomplete in three of the requirements specified in any subpart of Requirement 1.

2.4. Level 4:

2.4.1. The Transmission Owner reported more than one Category 1 transmission vegetation-related outage in a calendar year, or;

2.4.2. The TVMP was incomplete in four or more of the requirements specified in any subpart of Requirement 1.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
Version 1	TBA	1. Added “Standard Development Roadmap.” 2. Changed “60” to “Sixty” in section A, 5.2. 3. Added “Proposed Effective Date: April 7, 2006” to footer. 4. Added “Draft 3: November 17, 2005” to footer.	01/20/06

Standard FAC-003-1	Proposed Standard FAC-003-2 RBS Draft 4	Observations
Definitions of Terms **Right of Way** A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.	**Definitions of Terms Used in Standard** **Right-of-Way (ROW)** The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria. The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.	This definition is intended to more clearly recognize the establishment of the Right of Way thought documentation.
Vegetation Inspection The systematic examination of a transmission corridor to document vegetation conditions.	**Vegetation Inspection** The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.	This definition is intended to explain the reason for Vegetation Inspections, and to make clear that entities may perform other inspections at the same time as the Vegetation Inspection.

Standard FAC-003-1	Proposed Standard FAC-003-2 RBS Draft 4	Observations
	The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently. Current definition of Vegetation Inspection: The systematic examination of a transmission corridor to document vegetation conditions.	
	Minimum Vegetation Clearance Distance (MVCD) The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.	This definition was added to ensure a consistent understanding of the phrase.
3. Purpose: To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and	**3. Purpose:** To maintain a reliable electric transmission system by using a defense-in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation-related outages that could lead to Cascading.	Results based purpose, driven by Needs and Goals. NEED: To maintain a reliable electric transmission system , preventing the risk of those vegetation-related outages that could lead to Cascading. GOAL: To manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW

Standard FAC-003-1	Proposed Standard FAC-003-2 RBS Draft 4	Observations
reporting vegetation related outages of the transmission systems to the respective Regional Reliability Organizations (RRO) and the North American Electric Reliability Council (NERC).		
4. Applicability: **4.1.** Transmission Owner **4.2.** Regional Reliability Organization **4.3.** This Standard shall apply to all transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RRO as critical to the reliability of the electric system in the region.	4.1. Functional Entities: 4.1.1 Transmission Owners 4.2. Facilities: Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal , state, provincial, public, private, or tribal entities: 4.2.1. Each overhead transmission line operated at 200kV or higher. 4.2.2. Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator. 4.2.3. Each overhead transmission line operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC. 4.2.4. Each overhead transmission line identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.	4.1.1 replaces 4.1. 4.2 has been removed, as the requirements related to the RRO have been addressed in the compliance section of the standard. 4.2 replaces 4.3. This is superior, as it raises the bar on what lines need to be included within the applicability of this standard. To the extent the areas not covered in 4.2.4 need to be addressed, they should do so under another project and possibly in a separate standard, as the requirements for vegetation management performed in these areas by the GO and DP may be somewhat different than those performed by a Transmission Owner.

Standard FAC-003-1	Proposed Standard FAC-003-2 RBS Draft 4	Observations
	Rationale The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) NERC has a project in place to address at a later date the applicability of this standard to Generation Owners. 4) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.	

R1. The Transmission Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the Transmission Owner's objectives, practices, approved procedures, and work specifications**1**.	**R3.** Each Transmission Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that include(s) the following: **Rationale** The documentation provides a basis for evaluating the competency of the Transmission Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the Transmission Owner avoids vegetation-to-wire conflicts under all Ratings and all Rated Electrical Operating Conditions. See Figure 1 for an illustration of possible conductor locations.	R3 replaces R1.
R1.1. The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation	R6. Each Transmission Owner shall perform a Vegetation Inspection of 100% of its applicable transmission lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18	R6 replaces R1.1. R6 is superior because it requires entities to take action (perform the inspection), rather than just create a schedule.

and any other environmental or operational factors that could impact the relationship of vegetation to the Transmission Owner's transmission lines.	calendar months between inspections on the same ROW.1 **Rationale** Inspections are used by Transmission Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.	
R1.2. The Transmission Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design	**R3.** Each Transmission Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that include(s)accounts for the following	Requirement R3 and Parts 3.1 and 3.2 replace the concept of "Clearance 1," as discussed in R1.2 and R1.2.1.

[1] When the Transmission Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO is granted a time extension that is equivalent to the duration of the time the TO was prevented from performing the Vegetation Inspection.

loading, and the effects of wind velocities on conductor sway. Specifically, the Transmission Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors. **R1.2.1.** Clearance 1 — The Transmission Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.	**3.1** Movement of applicable line conductors under their Rating and all Rated Electrical Operating Conditions; **3.2** Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.	

R1.2.2. Clearance 2 — The Transmission Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These Transmission Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap. **R1.2.2.1** Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied. **R1.2.2.2** Where transmission system	**R1.** Each Transmission Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[2] [*Violation Risk Factor: High*] [*Time Horizon: Real-time*]: 1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage **R2.** Each Transmission Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are <u>not</u> either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[2] [*Violation Risk Factor:*	R1 item 1 and R2 item 2 replace Clearance 2 with the Gallet Equations. These are performance based, and superior to the existing standard, as they require the entities to perform an action (manage vegetation) rather than creating a document.

[2] This requirement does not apply to circumstances that are beyond the control of a Transmission Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

[3] If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.	*Medium*] [*Time Horizon: Real-time*]: 1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage[3],	
R1.3. All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner, to perform their duties.		R1.3 is ambiguous (what is "appropriate") and unenforceable (what if the Transmission Owner defines no qualifications or training), and was not included in the new version of the standard.
R1.4. Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner is restricted from attaining the clearances specified in Requirement 1.2.1.		R5 replaces R1.4. It is superior because it requires the Transmission Owner to take action (take corrective action), rather than to simply develop mitigation measures.
	R5. When a Transmission Owner is constrained from performing vegetation work on applicable transmission lines operating within their Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the Transmission Owner shall take corrective action to ensure continued vegetation management to prevent encroachments	

	Rationale Legal actions and other events may occur which result in constraints that prevent the Transmission Owner from performing planned vegetation maintenance work. In cases where the transmission line is put at potential risk due to constraints, the intent is for the Transmission Owner to put interim measures in place, rather than do nothing. The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.	
R1.5. Each Transmission Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.	**R4.** Each Transmission Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable line when the Transmission Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment. *[VRF – Medium] [Time Horizon – Real-time]*	R4 replaces R1.5. It is superior because it requires the Transmission Owner to take action (notify the control center) rather than document a process.

	Rationale This is to ensure expeditious communication between the Transmission Owner and the control center when a critical situation is confirmed.	
R2. The Transmission Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.	**R7.** Each Transmission Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include • Change in expected growth rate/ environmental factors • Circumstances that are beyond the control of a Transmission Owner[3] • Rescheduling work between growing seasons • Crew or contractor availability/ Mutual assistance agreements	R7 replaces R2. It is superior because it requires entities to takes specific action (complete 100% of its plan) rather than more generic language (implement its plan). Entities that do not have a plan would be unable to meet this requirement, as they would have no evidence to demonstrate compliance.

[3] Circumstances that are beyond the control of a Transmission Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or an applicable regulatory body.

	• Identified unanticipated high priority work • Weather conditions/Accessibility • Permitting delays • Land ownership changes/Change in land use by the landowner • Emerging technologies **Rationale** This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.	
R3. The Transmission Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission Owner to have been caused by vegetation. **R3.1.** Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24-hour period. **R3.2.** The Transmission Owner is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation related	**Periodic Data Submittal:** The Transmission Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their Rating and all Rated Electrical Operating Conditions as determined by the Transmission Owner to have been caused by vegetation, except as excluded in footnote 2, and including as a minimum the following: o The name of the circuit(s), the date, time and duration of the outage; the voltage of the circuit; a description of the cause of the outage; the category associated with the Sustained	Moved to compliance section of standard.

outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation). **R3.3.** The outage information provided by the Transmission Owner to the RRO, or the RRO's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner. **R3.4.** An outage shall be categorized as one of the following: **R3.4.1.** Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW; **R3.4.2.** Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW; **R3.4.3.** Category 3 — Fall-ins: Outages caused by vegetation falling into lines from	Outage; other pertinent comments; and any countermeasures taken by the Transmission Owner. A Sustained Outage is to be categorized as one of the following: o Category 1A — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, that are identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW; o Category 1B — Grow-ins: Sustained Outages caused by vegetation growing into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, by vegetation inside and/or outside of the ROW; o Category 2A — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, from within the ROW; o Category 2B — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, from within the ROW; o Category 3 — Fall-ins: Sustained Outages caused by vegetation falling into applicable lines from outside the ROW; o Category 4A — Blowing together: Sustained Outages caused by vegetation and applicable lines that are identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW. o Category 4B — Blowing together: Sustained	

outside the ROW. **R4.** The RRO shall report the outage information provided to it by Transmission Owner's, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the RRO as a result of any of the reported outages.	Outages caused by vegetation and applicable lines, but are not identified as an element of an IROL or Major WECC Transfer Path, blowing together from within the ROW. The Regional Entity will report the outage information provided by Transmission Owners, as per the above, quarterly to NERC, as well as any actions taken by the Regional Entity as a result of any of the reported Sustained Outages.	
	R1. Each Transmission Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below[2]: 1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage[3] , 2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage[4] , 3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[4], 4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage[4].	New requirement.

	Rationale Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2. Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a Transmission Owner's vegetation maintenance program: 1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program. 2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program. 3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program. 4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple	
	R2. Each Transmission Owner shall manage	New requirement.

	vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[2] [Violation Risk Factor: Medium] [Time Horizon: Real-time]: 1. An encroachment into the MVCD, observed in Real-time, absent a Sustained Outage[3], 2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage[4], 3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[4], 4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage[4]	

	Rationale Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2. Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a Transmission Owner's vegetation maintenance program: 1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program. 2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program. 3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program. 4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.	

[2] This requirement does not apply to circumstances that are beyond the control of a Transmission Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

[3] If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

[4] Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

Project 2007-07 Vegetation Management

New and Modified Definitions

The following definitions are proposed as part of project 2007-07. They have been provided separately for ease of reference.

Right-of-Way (ROW)

Current

A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.

Proposed

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner’s legal rights but may be less based on the aforementioned criteria.

Redline

~~A~~ The corridor of land ~~on which electric~~ under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built.~~s may be located.~~ The ROW width in no case exceeds the s may be located. Transmission Owner’s legal rights but may be less based on the aforementioned criteria. ~~may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.~~

Vegetation Inspection

Current

The systematic examination of a transmission corridor to document vegetation conditions.

Proposed

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner’s control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

Redline
The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.~~a transmission corridor to document vegetation conditions.~~

Minimum Vegetation Clearance Distance (MVCD)
Proposed (new)
The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2007-07 Vegetation Management

Consideration of Issues and Directives

Project 2007-07 Vegetation Management		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
We will not direct NERC to submit a modification to the general limitation on applicability as proposed in the NOPR. However, we will require the ERO to address the proposed modification through its Reliability Standards development process. As explained in the NOPR, the Commission is concerned that the bright-line applicability threshold of 200 kV will exclude a significant number of transmission lines that could impact Bulk-Power System reliability. Although the regional reliability organizations are given discretion to designate lower voltage lines under the proposed Reliability Standard, none have designated any operationally significant lines even though there are lower voltage lines involving IROL as suggested by Progress and SERC. We continue to be concerned that this approach will not prospectively result in the inclusion of all transmission lines that could impact Bulk-Power System reliability.	FERC Order 693, P706	The standard applies to the following facilities, including but not limited to those that cross lands owned by federal, state, provincial, public, private, or tribal entities: 1 - Each overhead transmission line operated at 200kV or higher. 2 - Overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator. 3 - Each overhead transmission line operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC. 4 - Each overhead transmission line identified above located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

In proposing to require the ERO to modify the Reliability Standard to apply to Bulk-Power System transmission lines that have an impact on reliability as determined by the ERO, we did not intend to make this Reliability Standard applicable to fewer facilities than it currently is with the 200 kV bright line applicability, but to extend the applicability to lower voltage facilities that have an impact on reliability. We support the suggestions by Progress Energy, SERC and MISO to limit applicability to lower voltage lines associated with IROL and these suggestions should be part of the input to the Reliability Standards development process. Similarly, the ERO should evaluate the suggestions proposed by LPPC, APPA and Avista.	FERC Order 693, P706	The standard applies to the following facilities, including but not limited to those that cross lands owned by federal, state, provincial, public, private, or tribal entities: 1 - Each overhead transmission line operated at 200kV or higher. 2 - Overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator. 3 - Each overhead transmission line operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC. 4 - Each overhead transmission line identified above located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.
Accordingly, the Commission directs the ERO to develop a Reliability Standard that defines the minimum clearance needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal land and non-federal land.	FERC Order 693, P732	The standard includes Minimum Vegetation Clearance Distances based on the Gallet equations, as specified in FAC-003 Table 2. The standard applies to facilities that meet specific criteria, including (but not limited to) those that cross lands owned by federal, state, provincial, public, private, or tribal entities.

The Commission also directs the ERO to collect outage data for transmission outages of lines that cross both federal and non-federal lands, analyze it, and use the results of this analysis and information to develop a Reliability Standard that would apply to transmission lines crossing both federal and non-federal land.	FERC Order 693, P732	The ERO is currently collecting and publishing all outage data related to FAC-003. This data is received through quarterly reporting and self reporting of violations. Additionally, the TADS initiative is currently collecting data on all automatic interruptions, including those caused by vegetation, both on and off the right of way. This action is equally applicable to federal and non-federal lands. The SDT has requested the TADS project team to modify its database to include fields to identify Federal and non-Federal land transmission facilities such that this data can be collected.

We recognize that many commenters would like a more precise definition for the applicability of this Reliability Standard, and we direct the ERO to develop an acceptable definition that covers facilities that impact reliability but balances extending the applicability of this standard against unreasonably increasing the burden on transmission owners.	FERC Order 693, P708	The standard applies to all Transmission Owners, for the following facilities, including but not limited to those that cross lands owned by federal, state, provincial, public, private, or tribal entities: 1 - Each overhead transmission line operated at 200kV or higher. 2 - Overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator. 3 - Each overhead transmission line operated below 200 kV identified as an element of a Major WECC Transfer Path in the Bulk Electric System by WECC. 4 - Each overhead transmission line identified above located outside the fenced area of the switchyard, station or substation and any portion of the span of the transmission line that is crossing the substation fence.

FirstEnergy and Xcel suggest that if the applicability of this Reliability Standard is expanded, the Commission should allow flexibility in complying with this Reliability Standard for lower-voltage facilities, or allow lower-voltage facilities one year before the Reliability Standard is implemented. The ERO should consider these comments when determining when it would request that the modification of this Reliability Standard to go into effect.	FERC Order 693, P709	The Implementation Plan requests that the standard become effective as follows: "The first calendar day of the first calendar quarter one year after the date of the order approving the standard from applicable regulatory authorities where such explicit approval is required. Where no regulatory approval is required, the standard becomes effective on the first calendar day of the first calendar quarter one year after Board of Trustees adoption." Additionally, the Implementation Plan proposes four transition cases to address specific situations.
The Commission continues to be concerned with leaving complete discretion to the transmission owners in determining inspection cycles, which limits the effectiveness of the Reliability Standard. Accordingly, the Commission directs the ERO to develop compliance audit procedures, using relevant industry experts, which would identify appropriate inspection cycles based on local factors. These inspection cycles are to be used in compliance auditing of FAC-003-1 by the ERO or Regional Entity to ensure such inspection cycles and vegetation management requirements are properly met by the responsible entities.	FERC Order 693, P721	The VM SDT has tightened the Inspection Cycle requirement. Minimum inspection frequency of once per calendar year is now required.

FirstEnergy suggests that rights-of-way be defined to encompass the required clearance areas instead of the corresponding legal rights, and that the standards should not require clearing the entire right-of-way when the required clearance for an existing line does not take up the entire right-of-way. The Commission believes this suggestion is reasonable and should be addressed by the ERO. Accordingly, the Commission directs the ERO to address this suggestion in the Reliability Standards development process.	FERC Order 693, P734	The VMSDT developed a new definition of Active Transmission Line ROW for inclusion in NERC Glossary. This definition includes the statement "The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria." The Standard does not require the clearing the entire legal easement for a particular parcel of land to ensure reliability. Rather, the Standard requires vegetation maintenance to adequately prevent outages from vegetation on the right of way but also requires the TO to prevent encroachment within the MVCD.
It was pointed out that an entity did not need to be registered as a TO for FAC-003-1 to apply to them, only that they have transmission lines operated at 200 kV and above. This could include radial lines as well as generation leads at the 200kV and above level. This could mean functions other than TO would require FAC-003-1 to be in the audit scope. How are you looking at the applicability of FAC-003-1 as it applies to DPs, LSEs, GOs etc. This could be applicable to many entities registered in multiple regions.	NERC Audit Observation Team	This is currently addressed through entity registration and is also being addressed through Project 2010-07 Generator Requirements at the Transmission Interface
TO's shall demonstrate compliance through self certification. Compliance monitoring shall conduct an on-site audit every five years or more frequently as deemed appropriate. Does this over-ride the six year audit cycle for TO's?	NERC Audit Observation Team	The standard has been updated with the most current compliance information, eliminating this potential concern.

With regards to the vegetation management standard, what type of event would trigger a compliance investigation?	NERC Audit Observation Team	This question is outside the scope of the drafting team's work.
Format inconsistencies	Version 0 Team	The proposed standard has been formatted consistently.
RA vs. RRO	Version 0 Team	The proposed standard no longer refers to RAs or RROs. Additional, the Planning Coordinator has replaced the Region in a number of areas in which discretion might be required (e.g., identifying the criticality of an element).
Too weak on compliance	Version 0 Team	The Compliance section of the proposed standard now includes Time Horizons, Violation Severity Levels, and Violation Risk Factors to support a stronger position regarding compliance.

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Violation Risk Factor and Violation Severity Level Assignments

Project 2007-07 Vegetation Management

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in FAC-003-2 Vegetation Management.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors

The SDT applied the following NERC criteria when developing these VRFs:

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

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[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").

[2] Id. at footnote 15.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

VRF Justification

VRF for FAC-003-2, Requirements R1:

The SDT assigned this requirement a VRF of High.

- FERC's Guideline 2 — Consistency within a Reliability Standard. The Requirement states transmission owners must manage vegetation for lines that represent a significant risk of cascading, instability, or separation. The VRF is only applied at the Requirement level and each Requirement Part is treated equally.
- FERC's Guideline 3 — Consistency among Reliability Standards. The requirement mandates measurable performance with regard to vegetation management to ensure that the risk of cascading, separation, and instability is minimized. Other requirements with similar performance based outcomes that could lead to cascading, instability, or separation carry a High VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. IROLs and Major WECC Transfer Paths by definition have an increased potential for leading to cascading, separation, or instability. Therefore this requirement was assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. The requirement contains only one objective (to manage vegetation of lines that carry increased risk of instability, cascading, or separation) and only one VRF was assigned.

VRF for FAC-003-2, Requirements R2:

The SDT assigned this requirement a VRF of Medium.

- FERC's Guideline 2 — Consistency within a Reliability Standard. The Requirement states transmission owners must manage vegetation for lines that do not represent a significant risk of cascading, instability, or separation. The VRF is only applied at the Requirement level and each Requirement Part is treated equally.
- FERC's Guideline 3 — Consistency among Reliability Standards. The requirement mandates measurable performance with regard to vegetation management to ensure that the risk of equipment damage is minimized. Other requirements similar performance based outcomes that could lead to equipment damage carry a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Lines that are not IROLs and Major WECC Transfer Paths by definition have less potential for leading to cascading, separation, or instability. Therefore this requirement was assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. The requirement contains only one objective (to manage vegetation of lines that carry minimal risk instability, cascading, or separation) and only one VRF was assigned.

VRF for FAC-003-2, Requirements R3:

The SDT assigned this requirement a VRF of Lower.

- FERC's Guideline 2 — Consistency within a Reliability Standard. The Requirement mandates the Transmission Owner to have documented strategies, procedures, processes, or specifications. The VRF is only applied at the Requirement level and each Requirement Part is treated equally.
- FERC's Guideline 3 — Consistency among Reliability Standards. This requirement calls for an entity to have documented strategies, procedures, processes, or specifications. This requirement is administrative in nature, and is consistent with other standards requiring documentation.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to have a document is not likely to directly affect the electrical state or the capability of the bulk electric system, or the

ability to effectively monitor and control the bulk electric system. Development of the documents is a requirement that is administrative in nature and is in a planning time frame that, if violated, would not, under emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.. Therefore this requirement was assigned a Lower VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. R2 contains only one objective which is to have documents(s). Since the requirement is to have a documents, only one VRF was assigned.

VRF for FAC-003-2, Requirements R4:

The SDT assigned this requirement a VRF of Medium.

- FERC's Guideline 2 — Consistency within a Reliability Standard. The Requirement specifies that transmission owners must report vegetation conditions that are likely to cause a Fault to the control center holding switching authority for the associated line. The VRFs are only applied at the Requirement level and there are no Requirement Parts for separate consideration.
- FERC's Guideline 3 — Consistency among Reliability Standards. The requirement mandates notifications that could hinder the ability to effectively monitor and control the bulk electric system. Other requirements that address with similar outcomes are also assigned Medium VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to report vegetation conditions may affect the ability to effectively monitor and control the bulk electric system Therefore this requirement was assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. The requirement contains only one objective (to report) , and only one VRF was assigned.

VRF for FAC-003-2, Requirements R5:

The SDT assigned this requirement a VRF of Medium.

- FERC's Guideline 2 — Consistency within a Reliability Standard. The Requirement mandates that a Transmission Owner, when constrained from performing vegetation work that may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, must take corrective action to ensure continued vegetation management to prevent encroachments. The VRF is only applied at the Requirement level and there are no Requirement Parts for separate consideration.
- FERC's Guideline 3 — Consistency among Reliability Standards. The requirement mandates corrective action that, if not taken, could directly affect the electrical state or the capability of the bulk electric system. Other requirements with similar outcomes are also assigned Medium VRFs.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to take corrective action could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. Therefore this requirement was assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. The requirement contains only one objective (to take corrective action), and only one VRF was assigned.

VRF for FAC-003-2, Requirements R6:

The SDT assigned this requirement a VRF of Medium.

- FERC's Guideline 2 — Consistency within a Reliability Standard. The Requirement specifies that the transmission owner must perform a Vegetation Inspection of 100% of its lines at least once per calendar year. The VRFs are only applied at the Requirement level and there are no Requirement Parts for separate consideration.
- FERC's Guideline 3 — Consistency among Reliability Standards. The requirement mandates inspections that, if not performed, could affect the ability to effectively monitor and control the bulk electric system. Other requirements with similar outcomes are also assigned Medium VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to perform an inspection could affect the ability to effectively monitor and control the bulk electric system. Therefore this requirement was assigned a lower VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. The requirement contains only one objective (to perform a Vegetation inspection), and only one VRF was assigned.

VRF for FAC-003-2, Requirements R7:

The SDT assigned this requirement a VRF of Medium.

- FERC's Guideline 2 — Consistency within a Reliability Standard. The Requirement specifies that the Transmission Owner must complete 100% of its annual vegetation work plan. The VRFs are only applied at the Requirement level and there are no Requirement Parts for separate consideration.
- FERC's Guideline 3 — Consistency among Reliability Standards. The requirement mandates completion of work that, if not completed, could affect the electrical state or the capability of the bulk electric system. Other requirements with similar outcomes are also assigned Medium VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to complete the annual vegetation work plan could affect the electrical state or the capability of the bulk electric system. Therefore this requirement was assigned a lower VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. The Requirement contains only one objective (to complete 100% of the annual vegetation work plan), and only one VRF was assigned.

Justification for Assignment of Violation Severity Levels

In developing the VSLs, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

> Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VSLs for FAC-003-2 Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations..	This is a new requirement, and accordingly cannot lower the current level of compliance.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for FAC-003-2 Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	This is a new requirement, and accordingly cannot lower the current level of compliance.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for FAC-003-3 Requirement R3

R#	Compliance with NERC's Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The previous standard graded the VSLs based on the completeness of the TVMP. The new VSL is structured similarly, but has omitted the "Low" level, effectively raising the minimum level of compliance.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for FAC-003-3 Requirement R4:

R#	Compliance with NERC's Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The previous standard does not require actual communication, while the new standard does. Accordingly, this should be treated as a new requirement, and therefore cannot lower the current level of compliance.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for FAC-003-3 Requirement R5:

R#	Compliance with NERC's Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - Severe: The performance or product measured does not substantively meet the intent of the requirement.	The only VSL is Severe, and therefore, the VSL cannot result in a lower level of compliance.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for FAC-003-3 Requirement R6:

R#	Compliance with NERC's Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The previous standard does not require actual inspections, while the new standard does. Accordingly, this should be treated as a new requirement, and therefore cannot lower the current level of compliance.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for FAC-003-3 Requirement R7:

R#	Compliance with NERC's Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The VSLs in the previous standard were focused on completeness of the document, with the "Severe" VSL only reserved for entities that did not have or implement their plan. The proposed VSLs are graded based on the amount of the plan completed, giving a clear indication that partial completion is still a violation, establishing a level of compliance in excess of what was established previously.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

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Technical, Policy and Regulatory Issues Addressed by FAC-003 SDT

Q1: FERC generally requires that revised standards provide an adequate level of reliability in a manner that is at least as effective and efficient as the previously balloted and approved version of the standard. How does draft Standard FAC-003-2 meet this objective? Please provide specific explanation of how the portfolio of proposed requirements provides a defense-in-depth strategy for ensuring bulk power system reliability that is equally efficient and effective to or superior to the current Standard, FAC-003-1 — Transmission Vegetation Management Program. A specific explanation of how each requirement, when combined with the other requirements of the draft standard, contributes to a defense-in-depth strategy will be helpful.

A1: This Standard is more effective and efficient in ensuring an adequate level of reliability than FAC-003-1 because it has the following attributes.

- It removes the “fill-in-the-blank” ambiguity previously contained in FAC-003-1.
- It separates performance requirements (R1, R2, R4, R5, R6, and part of R7) from documentation requirements (R3 and the remainder of R7), and minimizes the burden of those documentation requirements.
- It has explicit and therefore clearer expectations to manage vegetation to: 1) prevent observable vegetation encroachments inside the Minimum Vegetation Clearance Distance (MVCD) and 2) prevent a confirmed Fault even in the absence of a Sustained Outage (R1, R2).
- It places more emphasis on those lines that pose the greatest risk to the reliability of the interconnected transmission system. This is accomplished by converting the previous FAC-00301 R1 into the new R1 and R2 and assigning the high VRF to the more important lines in R1.
- It requires the management of vegetation to prevent encroachments by specific types, which are indicative of the quality of that management. Those quality-related encroachment types also allow more specificity for determining the severity level of a violation.
- It establishes a clear, industry proven method for flash-over distance (clearance) that is not subject to external standards established for other purposes (through use of the Gallet Equations to establish the MCVD).
- It has an unambiguous expectation for Vegetation Inspection intervals.

- It separates inspections and communications of imminent threats into individual and clearer requirements that can be appropriately weighted by VRFs and VSLs (both of these items were previously addressed in sub-requirements of FAC-003-1 R1).
- It correctly moves reporting obligations from the requirements section (FAC-003-1 R3) to the Additional Compliance Information Section.
- It has additional supporting text in the Background, Rationale, and Guidelines and Technical Basis sections to aid the industry in using the Standard and understanding conductor dynamics and the interrelationship of vegetation growth, inspection frequencies, and vegetation control methods.
- It requires vegetation be managed with equal rigor over all lands regardless of the ownership of those lands.

This standard utilizes three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

a) Performance-based — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular bulk power system performance result or outcome*?

b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system*?

c) Competency-based — defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system*?

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

This NERC Vegetation Management Standard ("standard") uses a defense-in-depth approach to improve the reliability of the electric Transmission System by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);

- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Q2: The primary FERC directive in Order 693 is that the standard should specify minimum clearances to avoid Sustained Outages under all applicable conditions. Where in the Revised FAC-003-2 are references made to the 'all applicable conditions' issues? Is it understood that the revised standard is intended to protect facilities during emergency conditions?

A2: There are numerous references in the Standard to ensure that facilities are protected for all applicable conditions, including emergency conditions and conditions that would prevent the entity from carrying out its annual work plan. Those references are provided below along with a conclusion answer.

- See R1 and R2 which include the phrase "...operating within its **Rating and all Rated Electrical Operating Conditions.**"**(***Emphasis added)*
- Also see R3 which states:

"Each Transmission Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable lines that include(s) the following:

- 3.1 Accounts for the movement of applicable line conductors under their **Rating and all Rated Electrical Operating Conditions;** "

- Also see R5 which states "When a Transmission Owner is **constrained** from performing vegetation work on applicable lines operating within its **Rating and all Rated Electrical Operating Conditions,** and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the Transmission Owner **shall take corrective action** to ensure continued vegetation management to prevent encroachments**.**"

- Also see **Periodic Data Submittal:** The Transmission Owner will submit a quarterly report to its Regional Entity, or the Regional Entity's designee, identifying all Sustained Outages of applicable lines operated within their **Rating and all Rated Electrical Operating Conditions**

- Also see **Guideline and Technical Basis** discussion for Requirements R1, R2 and R3, which reinforces the concept that applicable line clearances are to be observed throughout a line's **Rating and under all Rated electrical Operating Conditions.**

The MVCD is the minimum clearance needed under all **Rating and Rated Electrical Operating Conditions**. The **Rated Electrical Operating Condition** is defined in the glossary as "the specified or reasonably anticipated conditions under which the electrical system or an individual electrical circuit is intend/designed to operate.' As such if there is an emergency rating for a line, it would be covered by this standard.

Q3: Cost and cost effectiveness management have been raised as issues by stakeholders, state regulators and some FERC commissioners. How will the Revised FAC-003-2 affect companies' abilities to perform ROW maintenance in the most cost effective manner that does not compromise reliability? Will the Revised FAC-003-2 facilitate or restrict companies from ensuring cost effective ROW maintenance compared to FAC-003-1?

A3: This is a Results Based Standard. It addresses core rules to ensure an adequate level of reliability and removes fill-in-the-blank requirements, as well as requirements for excessive documentation. It allows efficiency in Vegetation Inspections by allowing them to be combined with other line inspections, and it focuses more on "what" to do than "how" to do it. Altogether, this allows the applicable entity the latitude to choose the most cost effective methods to achieve compliance.

Q4: FAC-003-1 identifies two clearances in R1.2.1 and R1.2.2: a clearance to be achieved when performing vegetation management work (Clearance 1), and a minimum clearance to prevent flashover (Clearance 2). Revised FAC-003-2 only identifies the minimum clearance to prevent flashover (based on the Gallet equations), and does not identify a clearance to be achieved when performing vegetation management work. How does the new standard ensure that vegetation management work is performed that would provide a similar level of performance as is currently required? Does the removal of Clearance 1 provide public interest benefits or cost savings that should be considered by regulatory authorities and other stakeholders? i.e., there is a trade off from C1 & C2 to MVCD so how do we find comfort with this?

A4: The MVCD was chosen to replace Clearance 2 because it defines the distance that will prevent a flash-over based on tested and proven principles. The FAC-003-1 Clearance 2 was inappropriately based on worker safety considerations; FAC-003 is not a worker safety standard. The Revised FAC-003-2 is now based on science, and not on another ANSI safety standard which may change for reasons beyond the scope of this Standard.

Clearance 1 is an entity-specific fill-in-the blank requirement; as such, it was removed.

R3 requires that the entity's documented maintenance strategies must account for the movement of the conductors under their Rating(s) and all Rated Electrical Operating Conditions. This is superior to the previous Clearance 1, as it leaves the necessary latitude for the applicable entity to exercise its full easement rights to manage vegetation at the time the work is performed (through methods such as use of herbicides or mechanical means, which may result in the complete elimination of the vegetation). Such exercise of full easements rights is often more efficient than pruning to a Clearance 1. In some cases property owners have incorrectly interpreted Clearance 1 as a limitation on the applicable entities' vegetation management rights. Such incorrect interpretations can exacerbate the execution of best work practices. If an applicable entity was not exercising its full rights due to external pressures or due to the assumption that Clearance 1 was fully sufficient at the time of maintenance, that entity is now (under FAC-003-2) relieved of that assumption, which will lead more directly to the consideration of the most cost effective vegetation management method(s).

FAC-003-2 Requirement R5 states that when the applicable entity is constrained from performing vegetation work that may lead to an encroachment into the MVCD prior to the implementation of the next annual work plan that the entity shall take corrective *action to ensure continued vegetation management to prevent encroachments.* This ensures that the clearance obtained at the time work is performed will be fully adequate.

R6 requires an Annual Inspection which by its definition is "The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection". Therefore this inspection will identify annually those vegetation conditions that require attention regardless of how, when or to what clearance distance the work was last performed. As such the required inspection provides the mechanism to allow the applicable entity to address any work that must be performed even in advance of the next planned maintenance. Requirement R7 requires that the work plan be executed to ensure that no vegetation encroachments occur within the MVCD.

Therefore, separately and collectively R3, R5, R6 and R7 are superior to the previous requirement to establish a Clearance 1.

Q5: FAC-003-1 R1.3 required a transmission vegetation management program that mandated personnel involved in the establishment of the TVMP hold appropriate qualifications and training. How is this requirement addressed in the Revised FAC-003-2 or otherwise addressed in other NERC reliability standards?

A5: The FAC-003-1 requirement for "appropriate" qualifications and training was ambiguous and therefore removed. Applicable entities (as well as contractors that are retained by applicable entities to perform vegetation management) are subject to numerous state and federal environmental and worker safety regulations related to right of way work. Imposing additional NERC requirements for "appropriate" qualifications and training on personnel and contractors that may perform right of way maintenance is not helpful to reliability, and overly burdensome. To the extent such personnel qualifications are needed, they would be better addressed in the PER standards.

Q6: In one respect, revised FAC-003-2 appears to reduce applicability of the Standard. Section 4.2.4 indicates the Standard only applies to those transmission lines "outside the fenced area of the switchyard, station or substation or any portion of the span the transmission line that is crossing the substation fence." These areas are currently within the scope of FAC-003-1, and removing them from the Standard would appear to create a reliability gap. Is this correct? How is this reliability gap addressed?

A6: Transmission line right of way maintenance programs do not normally extend inside those fenced areas, and some of those areas require special access permissions for entry. There are no reported or known vegetation related outages that have occurred in those areas. The fenced areas under lines are typically either paved or maintained as grassy areas. The lines within fenced areas are usually very short in length as compared to the miles of line outside the fenced areas. The lands within the fenced area are typically held fee-simple, precluding the need for special easements to maintain vegetation. That land is typically maintained such that buses, switchgear, ground-mat grids, touch and step potentials mitigation, and switchyard maintenance are of highest priority and therefore tree growth is not allowed. The maintenance of those fenced areas is often performed by other specialized contractors that do not maintain transmission line Right-of-Way. The ownership of the line often changes at the switchyard fence. For all those reasons it is neither necessary nor practical to have this Standard apply inside those areas based on the premise that such a limitation would lower the bar or create a reliability gap.

Q7: Revised FAC-003-2 has a minimum inspection cycle requirement. Order 693 did not ask for a minimum inspection cycle. What is the technical need for this requirement? Does the addition of this requirement provide reliability benefits that offset changes to other requirements?

A7: In 693 the Commission noted its concern about minimizing outages and expressed support for a realistic inspection cycle. The Commission further directed the ERO to develop compliance audit procedures, using relevant industry experts, which would identify appropriate inspection cycles based on local factors. However, the Commission also expressed its support for a realistic inspection cycle and expressed concern when entities performed inspections on cycles of less than every 3 years or even "as needed". The Commission expressed concern with leaving complete discretion to the transmission owners in determining inspection cycles which could limit the effectiveness of the Reliability Standard.

The Team received industry feedback regarding their desire to perform vegetation surveys in conjunction with other line inspections, which are typically annual surveys. The Team then chose to request industry to comment on the adequacy of annual Vegetation Inspections with the condition that the Vegetation Inspection could be performed in conjunction with other inspections. Industry comments were highly supportive of this approach.

The annual inspection cycle requirement is viewed by the Team as realistic, clear, unambiguous, easily performed, and not overly burdensome, since inspections can be performed aerially, on the ground, and in conjunction with other inspections. Regional Entities can develop Regional Standards or supplements to require increased frequencies in their regions if they determine that their regional vegetation growth rates justify such an increase.

Development of compliance audit procedures that account for local factors was considered and vetted by the Team. The Team concluded that the substantial variability in local factors would place undue burden on the ERO to develop continent-wide compliance audit procedures that would be clear and unambiguous. Furthermore the Team felt that waiting on the development of audit procedures and the implementation of those audit procedures could place Applicable Transmission Lines at greater risk than the proposed annual inspection cycle in FAC-003-2 which will provide a timelier "find-and-fix" solution to emerging problems with existing corrective and preventative maintenance processes. The Team suggests that the Annual Inspection requirement will ensure that applicable entities "find those conditions...likely to pose a hazard to the line prior to the next planned maintenance or inspection." This alternative approach accomplishes the reliability objective targeted by the Commission of identifying appropriate inspection cycles based on local factors.

Q8: Revised FAC-003-2 requires in R7 that the Transmission Owner "complete 100% of its annual vegetation work plan of applicable lines." What is required to be included in the plan? How does this differ from what is required under FAC-003-1 R1 and R2?

A8: The annual work plan will need to include the planned vegetation maintenance work necessary to ensure no vegetation encroachments occur within the MVCD. Regarding how this approach differs from FAC-003-1 Requirement 1 (which is about the documentation of practices and is silent on annual work planning), FAC-003-2 addresses similar documentation in Requirement R3. As far as how this approach differs from R2 in FAC-003-1, this FAC-003-2 Requirement 7 is not about details of creation of a plan with prescriptive descriptions of "how to" contents; it focuses instead on the necessary end results: specifically, work execution necessary to ensure no vegetation encroachments occur within the MVCD.

R7 continues to allow adjustments or modifications to the work plan and gives various examples to aid users of the Standard.

Q9: It appears that the SDT based the VSLs for R1 and R2 on the reliability consequences of an encroachment, rather than whether or not an encroachment occurred. NERC standards address consequences as an aspect of risk through the Violation Risk Factor, rather than the VSL. Why is the team choosing to attempt to address reliability consequences in both the VRF and the VSL?

A9: The action verb in R1 and R2 is to "manage." The Subject Matter Experts on the team, with industry feedback, recognized that the types of encroachments provide a valuable method to determine the effectiveness of a vegetation program's ability to manage vegetation effectively.

The most egregious vegetation management failure, and the most predictable, is to allow vegetation that is directly under the line to continue growing until it contacts the conductor. An entity that is unable to meet this obligation either does not have a vegetation program of significant value or doers but is not implementing it faithfully.

The next most obvious vegetation management failure mode would be vegetation that has grown adjacent to the line sufficiently close such that the line and vegetation could be blown together. In this case, the entity is likely implementing a relatively effective program, but was unable to identify this particular risk.

Less obvious and less predictable vegetation management failures are caused by falling trees that are tall enough to lodge into the line and cause a Sustained Outage. This is due to the challenges in predicting the various causes for and the numerous ways that trees fail (decay, erosion, defects, excavation, wind forces) and fall and the likely direction (up to 360 degrees available) that the tree will fall. An entity can have a very effective program, but fail to mitigate a risk of such occurrence.

Along with the difficulties just stated, it is deemed an even lesser vegetation maintenance failure to not find and remove every single tree before it has grown just enough to fall near the line and cause a brief Fault when it falls; or growth that reaches within the MVCD, but has not caused a fault. Again, an entity can have a very effective program, but fail to mitigate a risk of such occurrence.

Accordingly, the Team believes that the type and result of encroachment is indicative of an entity's overall performance and ability to "manage" vegetation.

Q10: Revised FAC-003-2 under R1 assigns a high VRF to those lines that are part of an IROL and/or are a WECC transfer path. Encroachment violations for all other lines are assigned a Medium VRF under R2. In the previous version of the standard, all lines were subject to the same requirements (i.e., the clearances were specified for all lines in R1.2, and clearances for all lines were expected to be maintained under R2). Splitting these elements into two different requirements, with two different VRFs, may create the perception that FAC-003-2 is "lowering the bar" by either reducing performance requirements or reducing potential penalties. How does the standard ensure that this "lowering" of the bar will not occur? Alternately, if this "lowering" is intentional, why is this reduction in expected performance or penalties reasonable and in the public interest?

A10: The reliability risk incurred by the outage of a transmission line within the interconnected transmission network is higher for some lines than for others. NERC's VRF definitions indicate that a High Violation Risk Factor is only appropriate for:

> A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

In FERC's May 18, 2007 Order on Violation Risk Factors, FERC identified Guideline 5, which states that where a single requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment must not be "watered down" to reflect the lower risk level associated with the less important objective. By not drawing a distinction between those lines with the ability to cause instability, separation, and cascading and those that do not, the previous standard co-mingled these objectives, and appropriately had a VRF of High assigned. However, the Team has chosen to eliminate that co-mingling, has split the requirement, and has accordingly assigned the appropriate VRFs to the separate requirements.

From a practical perspective, FAC-003-2 continues to find applicable entities in violation for all the types of encroachments that they were subject to in FAC-003-1. FAC-003-2 requires all of the sub-200 kV IROL and WECC Major Transfer Path lines be included in the applicability, which provide more specificity than what was required in the previous version of the standard. There is now a clear inclusion of violations for those Faults confirmed-after-the-fact, as well as for confirmed MVCD encroachments that are found and removed prior to a Fault. Given the VRF definitions, FERC's guidance, and the above additional considerations, the Team believes FAC-003-2 continues to require an appropriate level of performance.

Standards Announcement

Project 2007-07 Vegetation Management
Now Open: Recirculation Ballot October 4-13, 2011

Now available

Project 2007-07 – Vegetation Management
A recirculation ballot window for FAC-003-2 – Transmission Vegetation Management and its associated implementation plan is open through **8 p.m. on Thursday, October 13, 2011**.

Instructions
Members of the ballot pool associated with this project may log in and submit their votes.

In the recirculation ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their prior votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the recirculation ballot window. If a ballot pool member does not participate in the recirculation ballot, that member's last vote cast in the successive ballot that ended on February 28, 2011 will be carried over and used to determine if there are sufficient affirmative votes for this standard to pass.

Background
FAC-003-1 is being revised to address several fill-in-the-blank requirements, directives from Order 693, and issues raised by stakeholders. A successive ballot closed in February 2011 and achieved a quorum of 79.28% and an approval of 79.34%. The drafting team has posted its consideration of comments from the successive ballot and has been working to address a set of questions posed by Standards Committee chairman Allen Mosher, aimed at documenting the technical justification for the proposed requirements and verifying that the team has addressed the associated directives from Order 693

Documents for this project, including clean and redline to the last posted versions of the standard, implementation plan, and technical reference and the drafting team's responses to the technical, policy, and regulatory questions posed by Chairman Mosher have been posted on the project webpage.

Next Steps
Voting results will be posted and announced after the ballot window closes. If the recirculation ballot achieves a quorum and ballot pool approval, the standard will be presented to the NERC Board of Trustees for adoption.

Standards Process
The Standard Processes Manual contains all the procedures governing the standards development process.

The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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NERC
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Standards Announcement

Project 2007-07 Transmission Vegetation Management Recirculation Ballot Results

Now available

Ballot Results for FAC-003-2 Transmission Vegetation Management
A recirculation ballot on revisions to FAC-003-2 – Transmission Vegetation Management concluded on Thursday, October 13, 2011. The standard was approved by the associated ballot pool.

Voting statistics for the standard are listed in the table below, and the Ballot Results Web page provides a link to the detailed results.

Standard	Ballot Results
FAC-003-2 – Transmission Vegetation Management	Quorum: 87.17% Approval: 86.25 %

Next Steps

The standard will be presented to the NERC Board of Trustees for adoption.

Background

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Ballot Results	
Ballot Name:	Project 2007-07 Vegetation Management_rc
Ballot Period:	10/4/2011 - 10/13/2011
Ballot Type:	recirculation
Total # Votes:	265
Total Ballot Pool:	304
Quorum:	**87.17 % The Quorum has been reached**
Weighted Segment Vote:	86.25 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	90	1	68	0.84	13	0.16	2	7
2 - Segment 2.	9	0.3	3	0.3	0	0	3	3
3 - Segment 3.	74	1	51	0.823	11	0.177	7	5
4 - Segment 4.	22	1	14	0.778	4	0.222	3	1
5 - Segment 5.	54	1	34	0.872	5	0.128	3	12
6 - Segment 6.	35	1	23	0.852	4	0.148	0	8
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.4	4	0.4	0	0	2	1
9 - Segment 9.	6	0.6	6	0.6	0	0	0	0
10 - Segment 10.	7	0.5	4	0.4	1	0.1	0	2
Totals	**304**	**6.8**	**207**	**5.865**	**38**	**0.935**	**20**	**39**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Negative	View
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	View
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Affirmative	View

1	BC Transmission Corporation	Gordon Rawlings	Affirmative	View
1	Beaches Energy Services	Joseph S Stonecipher	Negative	View
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	View
1	CenterPoint Energy	Paul Rocha	Negative	
1	Central Maine Power Company	Brian Conroy		
1	City of Vero Beach	Randall McCamish	Negative	View
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	View
1	Commonwealth Edison Co.	Daniel Brotzman		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Deseret Power	James Tucker	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	E.ON U.S.	Larry Monday		
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	View
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Negative	View
1	GDS Associates, Inc.	Claudiu Cadar	Abstain	
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Negative	View
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stanley T Rzad	Negative	View
1	Lake Worth Utilities	Walt J Gill	Negative	View
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca	Negative	View
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Negative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	Metropolitan Water District of Southern California	Ernest Hahn	Abstain	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	View
1	National Grid	Saurabh Saksena	Affirmative	View
1	Nebraska Public Power District	Richard L. Koch	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Henry G. Masti	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Michael T. Quinn	Affirmative	View
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson		
1	Pacific Gas and Electric Company	Chifong Thomas		
1	PacifiCorp	Mark Sampson		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	Frank F Afranji	Affirmative	
1	Potomac Electric Power Co.	Richard J Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	View
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Chelan County	Chad Bowman	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	

1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	View
1	South Texas Electric Cooperative	Richard McLeon	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	View
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Keith Carman	Affirmative	View
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	View
2	Alberta Electric System Operator	Mark B Thompson	Abstain	View
2	BC Transmission Corporation	Faramarz Amjadi		
2	Electric Reliability Council of Texas, Inc.	Charles B Manning		
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	Midwest ISO, Inc.	Jason L Marshall	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	Tom Bowe	Abstain	
2	Southwest Power Pool, Inc.	Charles Yeung		
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	American Electric Power	Raj Rana	Affirmative	
3	APS	Steven Norris	Negative	View
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	View
3	Blue Ridge Power Agency	Duane S Dahlquist	Negative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	View
3	City of Bartow, Florida	Matt Culverhouse	Abstain	View
3	City of Clewiston	Lynne Mila	Negative	
3	City of Green Cove Springs	Gregg R Griffin	Abstain	
3	City of Leesburg	Phil Janik	Negative	
3	Cleco Utility Group	Bryan Y Harper	Negative	View
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Constellation Energy	Carolyn Ingersoll	Affirmative	
3	Consumers Energy	David A. Lapinski	Negative	View
3	Consumers Power Inc.	Roman Gillen	Abstain	
3	Cowlitz County PUD	Russell A Noble	Affirmative	View
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	View
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Municipal Power Agency	Joe McKinney	Negative	View
3	Florida Power Corporation	Lee Schuster	Affirmative	View
3	Gainesville Regional Utilities	Kenneth Simmons		
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia System Operations Corporation	Scott S. Barfield-McGinnis	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	View
3	Lakeland Electric	Mace Hunter	Affirmative	View
3	Lincoln Electric System	Bruce Merrill	Affirmative	View
3	Los Angeles Department of Water & Power	Kenneth Silver		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	

3	MEAG Power	Steven Grego	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley	Affirmative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Abstain	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	Ocala Electric Utility	David Anderson	Negative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	OTP Wholesale Marketing	Bradley Tollerson		
3	PacifiCorp	John Apperson	Affirmative	
3	PECO Energy an Exelon Co.	Vincent J. Catania		
3	Platte River Power Authority	Terry L Baker	Affirmative	View
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Abstain	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salmon River Electric Cooperative	Ken Dizes	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson	Affirmative	
3	Santee Cooper	Zack Dusenbury	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	View
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Springfield Utility Board	Jeff Nelson	Abstain	
3	Tampa Electric Co.	Ronald L Donahey	Affirmative	
3	Turlock Irrigation District	Casey Hashimoto	Affirmative	
3	Umatilla Electric Cooperative	Steve Eldrige	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	View
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Affirmative	
4	American Public Power Association	Allen Mosher	Affirmative	
4	City of Clewiston	Kevin McCarthy	Negative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	Consumers Energy	David Frank Ronk	Negative	View
4	Cowlitz County PUD	Rick Syring	Affirmative	View
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	View
4	Fort Pierce Utilities Authority	Thomas Richards	Negative	View
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	View
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Affirmative	View
5	Amerenue	Sam Dwyer	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	View
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Chelan County Public Utility District #1	John Yale	Affirmative	
5	City of Grand Island	Jeff Mead	Abstain	
5	City of Tallahassee	Alan Gale	Affirmative	
5	City Water, Light & Power of Springfield	Karl E. Kohlrus		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy	James B Lewis	Negative	View
5	Cowlitz County PUD	Bob Essex	Affirmative	View

5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Robert Smith	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	View
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Cynthia E Sulzer		
5	JEA	Donald Gilbert		
5	Kansas City Power & Light Co.	Scott Heidtbrink	Negative	
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lincoln Electric System	Dennis Florom		
5	Louisville Gas and Electric Co.	Charlie Martin		
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	Michael K Wilkerson		
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Otter Tail Power Company	Stacie Hebert	Affirmative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	View
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Portland General Electric Co.	Gary L Tingley	Affirmative	
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	
5	PPL Generation LLC	Mark A Heimbach		
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	View
5	Public Service Enterprise Group Incorporated	Dominick Grasso	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik	Abstain	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	South California Edison Company	Ahmad Sanati		
5	South Carolina Electric & Gas Co.	Richard Jones		
5	South Mississippi Electric Power Association	Jerry W Johnson	Affirmative	
5	Tenaska, Inc.	Scott M Helyer	Negative	
5	Tennessee Valley Authority	George T. Ballew	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan		
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	View
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	View
6	Cleco Power LLC	Matthew D Cripps	Negative	View
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda Powell	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View
6	Florida Municipal Power Pool	Thomas Washburn	Negative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	View
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Thomas Saitta	Negative	View
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	View
6	Louisville Gas and Electric Co.	Daryn Barker		
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	New York Power Authority	Thomas Papadopoulos		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	OTP Wholesale Marketing	Bruce Glorvigen		
6	PacifiCorp	Gregory D Maxfield		

6	Progress Energy	John T Sturgeon	Affirmative	View
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	RRI Energy	Trent Carlson		
6	Salt River Project	Mike Hummel		
6	Santee Cooper	Suzanne Ritter	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Western Area Power Administration - UGP Marketing	John Stonebarger		
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Pacific Northwest Generating Cooperative	Margaret Ryan	Abstain	
8	Power Energy Group LLC	Peggy Abbadini		
8	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	View
8	Volkmann Consulting, Inc.	Terry Volkmann	Abstain	
9	California Energy Commission	William M Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
9	Oregon Public Utility Commission	Jerome Murray	Affirmative	
9	Public Service Commission of South Carolina	Philip Riley	Affirmative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Midwest Reliability Organization	Dan R Schoenecker		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith	Negative	View
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Southwest Power Pool RE	Stacy Dochoda		
10	Western Electricity Coordinating Council	Louise McCarren	Affirmative	

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Account Log-In/Register

Exhibit H

Standard Drafting Team Roster for NERC Standards Development Project 2007-07 Vegetation Management

VMSDT Bios

Ron Adams is General Manager, Right of Way Management at Duke Energy in Charlotte, NC. His current responsibilities include operational management of both Transmission and Distribution Rights of Way, which consist of over 100,000 miles of overhead T&D facilities. He has held many positions in his 26 year career, such as Substation Engineer, Industrial Marketing Specialist, Power Quality Engineer, Technical Services Manager, Manager of Design Engineering, Manager Engineering, Transmission Construction Manager, Transmission Operations Manager, and previously Director Vegetation Management Carolinas.

Mr. Adams is a Senior Member of IEEE, a former EPRI Innovator Award recipient for his Power Quality work, and a former Chair of the Canadian Electricity Association Work Group for Substation Life Cycle Management. He holds a Bachelor of Science degree in Electrical Engineering from Clemson University, and is a registered professional engineer in the states of North and South Carolina.

Tom Anderson is presently Lead Forester of Lincoln Electric System's Vegetation Management Team. Tom has worked at Lincoln Electric System (LES) since 1974. He has been involved with or supervised the installation and maintenance of LES's overhead and underground facilities at all distribution and transmission line voltages, and coordinated and completed LES's first TVMP and annual work plans for compliance with FAC-003-1. Mr. Anderson has supervised Locating and Troubleshooting Technicians and Thermography Technicians, and has also served as Trainer of Apprentice Line Technicians, 1st Class Line Technicians, and T&D Dispatchers.

Mr. Anderson has served as President of the International Brotherhood of Electrical Workers (IBEW) Local 1536 for 12 years. He has competed in the IBEW International Lineman Rodeo, and as a part of the LES team, has been awarded First Place for Underground Splicing. He has also been judge of the "Hurt Man Rescue" for several years in the American Public Power Association Line Technician Rodeo.

Mr. Anderson has served on the Board of Advisors for the Northeast Community College in Norfolk, Nebraska. During this period, Tom attempted to develop an Associate Degree program for Line Clearance Arborists, recognizing that the industry needs better trained and qualified personnel n this area.

Mr. Anderson has Bachelor of Arts degrees in Human Resources and in Industrial Management from Doane College. He also has an Associate of Arts degree in Computer Programming from Southeast Community College System, and is a NERC Certified Operator for LES transmission system.

Paul S. Beaulieu is a Professional Engineer with Finley Engineering Company. He has been involved in the electric utility industry for the past 28 years. Prior to joining Finley, he worked with Kansas City Power & Light (Great Plains Energy), a Midwest investor owned utility.

Mr. Beaulieu's has significant experience with design and construction of transmission, substation, and distribution projects ranging from 12 kV to 345kV, to managing transmission, (69kV and above) construction and maintenance resources over 47 counties across two states. His broad range of design experience for 34kV through 345kV transmission system projects includes: route selection, right of way descriptions, implementation and usage of transmission line design software, NESC code compliance determination, transmission line strength and loading profiles, structure and foundation design, bill of material and construction contracts and specifications. Additionally, he has provided the mechanical/civil design for 34 kV through 345kV substations including plans for grading and drainage, roadways, manholes and duct banks, foundations, apparatus layout, structure specifications, yard and interior lighting, lightning protection, station grounding, fencing design, control house development including foundation design, electrical layout, HVAC, plumbing, and house material specifications.

Mr. Beaulieu has also provided leadership to an efficiently run construction and maintenance organization. He had oversight responsibility for C&M activities, GIS integration, and Transmission Vegetation Management for 3,400 miles of transmission lines. Ultimately, he was responsible for new transmission construction and maintenance projects including ongoing asset management programs of the systems with an estimated plant value of $700 Million, assuring proper Project Scope and Cost Development and Project Management and Closeout.

Mr. Beaulieu earned his Master of Science in Mechanical and Aerospace Engineering from the University of Missouri Columbia (Emphasis Material Science, Fatigue and Fracture Mechanics) and his Bachelor of Science in Mechanical Engineering from the University of Missouri Kansas City. Additionally he earned an Associates of Science in Drafting Technology from Longview Community College.

Stephen Cieslewicz is President and Chief Consultant at CN Utility Consulting Inc. With more than 30 years of industry experience, Mr. Cieslewicz has established himself as a leading expert in utility vegetation management (UVM). This includes designing and running one of the nation's largest UVM programs (PG&E), managing large scale UVM related research projects, performing the industry's largest UVM benchmarking, and researching laws and regulations applicable to UVM. In working with utilities, regulators and service providers around the world, Mr. Cieslewicz has been directly involved in the bulk of tree and power line issues of note. He was a principal UVM investigator for the Joint U.S./Canada Power Systems Outage Task Force, a principal author of all UVM related reports following the August 14, 2003 blackout, and has been directly involved with the crafting or interpretation of UVM standards, best practices, and laws and regulations throughout the US and abroad.

An ISA Certified Arborist and Utility Specialist, Mr. Cieslewicz has testified as an expert at many significant legal, regulatory and legislative hearings. He is a past president of the Utility Arborist Association (UAA) and a recipient of numerous awards, including the UAA Utility Arborist Award, UAA President's Award, and certificates of appreciation from the U.S. and Canadian governments. Mr. Cieslewicz is also a well known speaker and author on UVM issues, and was recently selected by Green Media (publisher of Arbor Age, Landscape and Irrigation, Outdoor Power Equipment and Sports Turf) as one of eight most influential people in the green industry.

Orville Cocking is currently the Section Manager of the Transmission Line Maintenance Group at Consolidated Edison of New York, overseeing Transmission Line Maintenance and the Transmission Vegetation Management Program (TVMP). He has spent the last six years working in positions of increasing responsibilities in Central Engineering and Transmission Operations. He spent the 9 years prior to joining Consolidated Edison performing structural analysis of transmission and other unique structures as an engineering consultant.

Mr. Cocking has a Bachelor of Science degree in Civil Engineering, and is a licensed professional engineer in the states of New York, Delaware, and New Jersey.

Richard Dearman is a Senior Advisor on NERC Compliance at the Tennessee Valley Authority. Mr. Dearman has held numerous positions in engineering, maintenance and management within transmission and distribution since 1971. He has supported FEMA with investigations of disaster recovery claims on three occasions in Minnesota, Illinois, and Tennessee. In 1997, Mr. Dearman led a team within TVA that resulted in the reorganization and centralization of the TVA right-of-way maintenance program. He was assigned the management responsibility for the program at that that time, and held that position until April 2010. The interruption rate due to vegetation related outages declined to record low levels under Mr. Dearman's management. His 17 years management experience in transmission line right of way maintenance culminated in responsibility for TVA's full program oversight for over 17,000 miles of transmission lines with annual expenditures in excess of $19M in FY 2009.

Mr. Dearman served on the NERC Outage Investigation Team as a transmission industry expert/representative to perform field investigations of tree related interruptions that were associated with the August 14, 2003 blackout. He was the first Chairman of the SERC Vegetation Management Subcommittee inn 2004, and held that position for 5 years.

Mr. Dearman has participated in two industry peer reviews of transmission system vegetation maintenance programs sponsored by the North American Transmission Forum, and has led an EPRI project to reduce Human Errors in Switching Safety and Reliability. He has also led numerous safety and human performance improvement initiatives, projects, and investigations at TVA. He is well known within TVA for his investigative abilities to determine causes for transmission system interruptions, including (but not limited to) suspected and actual vegetation related outages.

Mr. Dearman holds a Bachelor of Science degree in Electrical Engineering, as well as an Master in Business Administration degree, and is a Registered Professional Engineer

Randall F. Gann

Randall Gann is the Manager of Power Delivery Contract Services for Alabama Power Company. He has held this position for the past 10 years. Part of Mr. Gann's responsibilities while holding this position has included vegetation management for 70,000 miles of distribution voltage lines and over 10,000 miles of transmission voltage lines. Prior to this, Mr. Gann held positions as Manager of Transmission Line Design and Transmission Line Construction for 8 years. He has worked the remainder of his career in various supervisory and engineering positions for Alabama Power Company in distribution and transmission operations and maintenance; and also Nuclear Generation Construction. Mr. Gann has over 40 years experience with the Southern Company, and is a member of the Vegetation Management Sub-Committee reporting to the SERC Operating Committee.

Mr. Gann holds a Bachelor of Science degree from Auburn University in Electrical Engineering and is a registered Professional Engineer in the State of Alabama.

Jeff Hackman is Manager – Transmission Operations for Ameren. In this role, he has responsibility for Transmission and Balancing Authority Operations, EMS support for Operations, Transmission Construction and Maintenance, Transmission Vegetation Management, Transmission Design, and Transmission Project Management. Mr. Hackman has been with Ameren or its predecessor companies since 1980. He has held many positions with increasing responsibility in transmission planning, design, and operations. Mr. Hackman has also held supervisory or management positions in distribution line design and distribution operations, including overhead and underground maintenance and construction activities. He has also performed studies to support power plant operation, and was responsible for engineering and design for distribution gas service in one of Ameren's divisions.

Mr. Hackman has conducted research and published/presented papers on insulation degradation and insulator design to prevent flashover in contaminated environments. He was the Missouri Society of Professional Engineers – St Louis Chapter "Young Engineer of the Year," and is currently a Senior Member of the IEEE. Hackman received earned his Bachelor of Science degree in Electrical Engineering from the University of Missouri – Rolla (now Missouri University of Science & Technology), and a Master of Arts degree in Business Administration from Webster University. He is a registered professional engineer in Missouri.

David Morrell is a Utility Environmental Analyst with the New York State Department of Public Service (the Department). He holds an Associate of Applied Science degree in Land Management and a Bachelor of Science in Forestry degree, with a specialization in Forest Resource Management.

Mr. Morrell has been with the NYS Department of Public Service for 21 years. Much of this time has been spent overseeing NY's Investor Owned Utilities ROW vegetation management programs pursuant to the Departments regulations. Mr. Morrell served on the first NERC vegetation standard drafting team, has written a number of the Departments recent regulations pertaining to ROW management, sits on ROW management training committees, and has authored a number of peer reviewed papers regarding issues in ROW management. Mr. Morell worked in the utility industry in the areas of T&D vegetation management and inspection for 5 years prior to joining the Department.

Mr. Morrell is a Certified ROW Pesticide Applicator and has received Departmental awards and recognitions for outstanding performance.

John Pinney is currently the Lead Transmission Forester for Progress Energy Florida, and been involved in utility vegetation management for the past 16 years. He is in charge of Progress Energy Florida's transmission vegetation management program and responsible the associated compliance program and documentation. Additionally, Mr. Pinney has worked for two utilities in the past in supervisory and management roles related to vegetation management for transmission and distribution.

A certified arborist, Mr. Pinney also holds membership in the International Society of Arboriculture and the Utility Arborists Association, and holds a pesticide applicators license in the state of Florida.

John Schechter is Manager of American Electric Power's Protection & Control Engineering office in Columbus, Ohio. Mr. Schechter has been with American Electric Power (AEP) or its operating companies since 1980. He has held many positions with increasing responsibility over the past thirty years, in areas of substation operation, construction, maintenance, and engineering. Mr. Schechter has also held supervisory or managerial positions in distribution line design, distribution service dispatching, and overhead and underground distribution maintenance and construction. For five years, he was responsible for the asset condition and forestry program for AEP's 35,000-mile transmission system, including over 8,000 miles of line operating above 200kV, and was accountable to state regulatory commission staff for the performance and compliance of AEP's transmission line assets.

Mr. Schechter served on the ECAR VM task force and has conducted presentations to promote vegetation standards at compliance workshops conducted by ERCOT, Southwest Power Pool and ReliabilityFirst. Mr. Schechter received his Bachelor of Science degree in electrical engineering from the University of Cincinnati, his Master of Science degree in electric power systems engineering from The Ohio State University, and his Master of Business Administration degree from the University of Notre Dame. He is a registered professional engineer in the states of Indiana and Ohio.

John Tamsberg is currently Manager of Transmission Vegetation Management for Florida Power and Light (FPL), where he manages the vegetation on 6,700 miles of Transmission in Florida and at 950 miles for NextEra Energy at sites across the US and Canada. Prior to his 25 years at FPL, Mr. Tamsberg spent 15 years working in state government, managing timber for the South Carolina Commission of Forestry and working for the Florida Division of Forestry in forest management, urban forestry and fire suppression.

With over 40 year's total experience in forestry and vegetation management, Mr. Tamsberg has served on a number of Urban Forestry and Landscape Advisory Boards. He served the International Society of Arboriculture on the Certification Test Committee, is past president of the Florida Urban Forestry Council, and is currently a member of the Arborist Certification Ethics Committee.

Mr. Tamsberg has a Bachelor of Science degree in Forestry from Clemson University, and is a Certified Arborist.

Stephen Tankersley is Operations Manager of Pacific Gas and Electric Company's (PG&E) Vegetation Management Department. He has been with PG&E for 34 years, holding a variety of positions of increasing responsibility in Engineering & Construction, Project Management, Financial and Business Systems Process Engineering, and most recently Vegetation Management, where he has served in his current position since 1999.

Mr. Tankersley has significant previous expertise in formal project/program management; process engineering; utility construction productivity; and computer systems design, development and implementation; and has used this expertise building PG&E's UVM program.

PG&E has one of the largest UVM programs in the nation, covering 70,000 sq. miles with 114,000 miles of overhead distribution and 20,000 miles of transmission, and operates under the strictest UVM regulatory environment in the country. Mr. Tankersley is a frequent speaker on topics related to UVM business operations, operating UVM programs in California's regulatory environment, and building effective UVM programs, and frequently contributes to UVM industry publications. Most recently, the Utility Arborist Association published an article by Mr. Tankerlsey discussing "Best Management Practices for Project Management Applied to Utility Vegetation Management."

Ron Turley is currently a Special Programs Manager for the Western Area Power Administration. He has 30 years experience in the electrical utility industry with the U.S. Department of Energy. Turley has over 28 years of management experience overseeing various combinations of engineering, construction and maintenance functions for high voltage transmission and substation facilities interconnecting Federal hydroelectric generation facilities such as Hoover, Glen Canyon and Flaming Gorge Dams in the Colorado River drainage basin. One of his current responsibilities involves the development and management of a vegetation management program for Western's Rocky Mountain Region which involves over 5000 miles of high voltage transmission across seven western states.

Mr. Turley was appointed by former Colorado Governor Ritter and retained by current Governor Hickenlooper on the Colorado Governor's Forest Health Advisory Council. He has frequently served as a technical industry expert to the Department of the Agriculture, U.S. Forest Service and Department of the Interior, Bureau of Land Management. Turley also serves on a number of other public organizations involved with the management of declining forest health and wildland fire issues affecting forested landscapes across the western United States and Canada. Mr. Turley holds a Bachelor of Science degree in Biological Science from the State University of New York at Binghamton and a Master of Science degree in Civil Engineering from Colorado State University.

Gary White is a Vegetation Management Program Manager – Forester for Oncor Electric Delivery LLC. Oncor's T&D system consists of approximately 113,000 miles of distribution facilities and 15,000 miles of transmission. For the last six years, Mr. White has been in the Asset Management – Maintenance Strategy and Planning workgroup responsible for VM strategy and planning. Prior to this position, Mr. White held various positions within Oncor's Vegetation Management workgroup for 24 years. He worked for a national line clearance company for 4 years prior to joining Oncor.

Mr. White holds a Bachelor of Science-Forestry degree from Stephen F. Austin State University. He holds a Texas Department of Agriculture Non Commercial Applicators license. He is a member of the International Society of Arboriculture (ISA) and a Certified Arborist and Utility Specialist through the ISA. He is a member of the Utility Arborists Association and a charter member and past president of the International Society of Arboriculture -Texas Chapter.

Phil Whitmer is the Transmission Compliance Manager for Georgia Power Company. He joined Georgia Power in 1980. During his career, he served ten years in Distribution Engineering, seven years in Industrial Marketing, six years in Transmission Line and Substation Maintenance, eight years in Transmission System Operations, and one year in Compliance.

Mr. Whitmer holds a Bachelor of Science degree in Electrical Engineering from the Georgia Institute of Technology and a Master in Business Administration degree from Augusta State University. He also obtained his Certified Energy Manager certification in 1996.

Ken Wright is Lead Superintendent, Transmission Maintenance at Tucson Electric Power Company (TEP) in Tucson, AZ. His current responsibilities include Transmission Line Maintenance in Arizona and New Mexico and Distribution Line Vegetation Management in Arizona. He has held several positions in his 35 year career at TEP, including Substation Civil Engineer, Gas Engineer, Transmission Engineer, Superintendent-Transmission Line C&M, Civil & Transmission Engineering Manager and T & D Construction & Maintenance Manager.

Taking an early retirement in 1996, Mr. Wright opened and managed the Tucson Office for Engineering Consultants, Inc. and returned to TEP in 2002 to head up the Transmission Line Design, Maintenance and Construction Department. Mr. Wright is a member of the American Society of Civil Engineers. He is a Registered Civil Engineer and Registered Land Surveyor in Arizona, sits on two Boards of Director for non-profit organizations, and holds a Bachelor of Science degree in Civil Engineering from The University of Arizona.

Exhibit I

Transmission Vegetation Management – FAC-003-2 Technical Reference Document

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Transmission Vegetation Management

Standard FAC-003-2 Technical Reference

Prepared by the

North American Electric Reliability Corporation

Vegetation Management Standard Drafting Team for NERC Project 2007-07

September 30, 2011

RELIABILITY | ACCOUNTABILITY



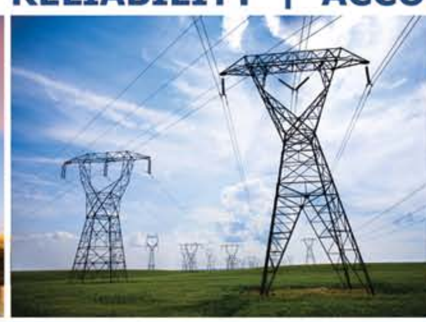


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Table of Contents

Disclaimer

This supporting document is supplemental to the reliability standard FAC-003-2 — Transmission Vegetation Management and does not contain mandatory requirements subject to compliance review. Throughout this document, for ready reference, there are “copies” in italic font of the wording in the Standard. Any “copy” of any part of the Standard in this document should be cross checked to the Standard and if any difference exists, then the Standard’s exact wording should be considered the intended wording for this document.

Introduction

This document is intended to provide supplemental information and guidance for complying with the requirements of Reliability Standard FAC-003-2.

The purpose of the Standard is to improve the reliability of the electric transmission system by preventing those vegetation related outages that could lead to Cascading.

Compliance with the Standard is mandatory and enforceable.

Special Note: The Application of the Results-Based Approach to FAC-003-2

In its three-year assessment as the ERO, NERC acknowledged stakeholder comments and committed to:

i) addressing quality issues to ensure each reliability standard has a clear statement of purpose, and has outcome-focused requirements that are clear and measurable; and
ii) eliminating requirements that do not have an impact on bulk power system reliability.

In 2010, the Standards Committee approved a recommendation to use Project 2007-07 Vegetation Management as a first proof of concept for developing results-based standards.

This standard is not intended to address outages such as those due to vegetation fall-ins or blow-ins from outside the Right-of-Way, vandalism, human activities or acts of nature. Operating experience indicates that trees that have grown out of specification have contributed to Cascading, especially under heavy electrical loading conditions.

This standard utilizes three types of requirements to provide layers of protection to prevent vegetation related outages that could lead to Cascading:

a) Performance-based — defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome*?
b) Risk-based — preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome *<u>that reduces a stated risk to the reliability of the bulk power system</u>*?
c) Competency-based — defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability <u>of the bulk power system</u>*?

The defense-in-depth strategy for reliability standards development recognizes that each requirement in a NERC reliability standard has a role in preventing system failures, and that these roles are complementary and reinforcing. Reliability standards should not be viewed as a body of unrelated requirements, but rather should be viewed as part of a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comport with the quality objectives of a reliability standard.

This NERC Vegetation Management Standard ("standard") uses a defense-in-depth approach to improve the reliability of the electric Transmission System by:

- Requiring that vegetation be managed to prevent vegetation encroachment inside the flash-over clearance (R1 and R2);
- Requiring documentation of the maintenance strategies, procedures, processes and specifications used to manage vegetation to prevent potential flash-over conditions including consideration of 1) conductor dynamics and 2) the interrelationships between vegetation growth rates, control methods and the inspection frequency (R3);
- Requiring timely notification to the appropriate control center of vegetation conditions that could cause a flash-over at any moment (R4);
- Requiring corrective actions to ensure that flash-over distances will not be violated due to work constrains such as legal injunctions (R5);
- Requiring inspections of vegetation conditions to be performed annually (R6); and
- Requiring that the annual work needed to prevent flash-over is completed (R7).

For this standard, the requirements have been developed as follows:

- Performance-based: Requirements 1 and 2
- Competency-based: Requirement 3
- Risk-based: Requirements 4, 5, 6 and 7

R3 serves as the first line of defense by ensuring that entities understand the problem they are trying to manage and have fully developed strategies and plans to manage the problem. R1, R2, and R7 serve as the second line of defense by requiring that entities carry out their plans and manage vegetation. R6, which requires inspections, may be either a part of the first line of defense (as input into the strategies and plans) or as a third line of defense (as a check of the first and second lines of defense). R4 serves as the final line of defense, as it addresses cases in which all the other lines of defense have failed.

Major outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. Adherence to the standard requirements for applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee, will reduce and manage this risk. For the purpose of the standard the term "public lands" includes municipal lands, village lands, city lands, and a host of other governmental entities.

The standard addresses vegetation management along applicable overhead lines and does not apply to underground lines, submarine lines or to line sections inside an electric station boundary.

The standard focuses on transmission lines to prevent those vegetation related outages that could lead to Cascading. It is not intended to prevent customer outages due to tree contact with lower voltage distribution system lines. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this standard is not written to address such isolated situations which have little impact on the overall electric transmission system.
Since vegetation growth is constant and always present, unmanaged vegetation poses an increased outage risk, especially when numerous transmission lines are operating at or near their Rating. This can present a significant risk of consecutive line failures when lines are experiencing large sags thereby leading to Cascading. Once the first line fails the shift of the current to the other lines and/or the increasing system loads will lead to the second and subsequent line failures as contact to the vegetation under those lines occurs. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are not an interrelated function of the shift of currents or the increasing system loading. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this standard places the highest priority on the management of vegetation to prevent vegetation grow-ins.

The drafting team reviewed and edited version 1 of FAC-003-1 to remove prescriptive and administrative language in order to distill the technical requirements down to their essential reliability content. Explanatory text is offered within two special sections, <u>Background</u> and <u>Guideline and Technical Basis</u>, to aid in understanding the standard and its requirements. <u>Rationale</u> text boxes and other text boxes are also inserted throughout the standard to aid understanding the sections. The <u>Effective Dates</u> section covers five special cases for lines that undergo specific transitions as or after the standard has reached the general effective date.

Preface

The NERC Vegetation Management Standard Drafting Team (VM SDT) acknowledges those across the industry who contributed to the development of this Standard and companion Technical Reference document. This Technical Reference document is intended to provide supplemental explanatory background and guidance related to requirements contained in the Standard but does not in itself contain requirements subject to compliance review.

The Standard requires the Transmission Owner to have documentation of the maintenance strategies or procedures or processes or specifications it uses to be successful in managing vegetation. This allows the Transmission Owner to exercise substantial flexibility in designing its overall program to meet its specific needs provided that the Transmission Owner also meets the purpose of the Standard.

While there are many approaches to vegetation management, the VMSDT supports industry best practices contained in ANSI A300 (Part 7) – Integrated Vegetation Management (IVM) practices on Utility Rights-of-way, as well as the companion publication Best Management Practices – Integrated Vegetation Management, as an effective strategy to maintain compliance with this Standard. ANSI A300 (Part 7), approved by industry consensus in 2006, contains many elements needed for an effective vegetation management. Those elements are similar to the requirements in this Standard. One key element is the "wire zone – border zone" concept. Supported by over 50 years of continuous research, wire zone – border zone is a proven method to manage vegetation on transmission rights-of-ways and is an industry accepted best practice to help ensure electric system reliability.

The VM SDT believes that Transmission Owners who adopt and effectively implement IVM principles, particularly the "wire zone – border zone" concept, are far less likely to experience a vegetation caused outage than those who do not.

Effective Dates & Special States of Transition

The first sentence of the Effective Dates section is standard language used in most NERC standards to cover the general effective date and is sufficient to cover the vast majority of situations. Five special cases are needed to cover effective dates for individual lines which undergo transitions after the general effective date. These special cases cover the effective dates for those lines which are initially becoming subject to the standard, those lines which are changing their applicability within the standard, and those lines which are changing in a manner that removes their applicability to the standard. The text for each of these five cases is copied from the standard and is shown below in italic font. An explanation of the need for each special exception follows each copied text section.

1. *A line operated below 200kV, designated by the Planning Coordinator as an element of an Interconnection Reliability Operating Limit (IROL) or designated by the Western Electricity Coordinating Council (WECC) as an element of a Major WECC Transfer Path, becomes subject to this standard the latter of: 1) 12 months after the date the Planning Coordinator or WECC initially designates the line as being an element of an IROL or an element of a Major WECC Transfer Path, or 2) January 1 of the planning year when the line is forecast to become an element of an IROL or an element of a Major WECC Transfer Path.*

Case 1 is needed because the Planning Coordinators may designate lines below 200 kV to become elements of an IROL or Major WECC Transfer Path in a future Planning Year (PY). For example, studies by the Planning Coordinator in 2011 may identify a line to have that designation beginning in PY 2021, ten years after the planning study is performed. It is not intended for the Standard to be immediately applicable to, or in effective for, that line until that future PY begins. The effective date provision for such lines ensures that the line will become subject to the standard on the January 1 of the PY specified with an allowance of at least 12 months for the Transmission Owner to make the necessary preparations to achieve compliance on that line. The table below has some explanatory examples of the application.

Date that Planning Study is completed	PY the line will become an IROL element	Date 1	Date 2	Effective Date The latter of Date 1 or Date 2
05/15/2011	2012	05/15/2012	01/01/2012	05/15/2012
05/15/2011	2013	05/15/2012	01/01/2013	01/01/2013
05/15/2011	2014	05/15/2012	01/01/2014	01/01/2014
05/15/2011	2021	05/15/2012	01/01/2021	01/01/2021

2. *A line operated below 200 kV currently subject to this standard as a designated element of an IROL or a Major WECC Transfer Path which has a specified date for the removal of such designation will no longer be subject to this standard effective on that specified date.*

Case 2 is needed because a line operating below 200kV designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network.

3. *A line operated at 200 kV or above, currently subject to this standard which is a designated element of an IROL or a Major WECC Transfer Path and which has a specified date for the removal of such designation will be subject to Requirement R2 and no longer be subject to Requirement R1 effective on that specified date*

Case 3 is needed because a line operating at 200 kV or above that once was designated as an element of an IROL or Major WECC Transfer Path may be removed from that designation due to system improvements, changes in generation, changes in loads or changes in studies and analysis of the network. Such changes result in the need to apply R1 to that line until that date is reached and then to apply R2 to that line thereafter.

4. *An existing transmission line operated at 200kV or higher which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date.*

Case 4 is needed because an existing line that is to be operated at 200 kV or above can be acquired by a Transmission Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the Transmission owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network which will thereafter make the line subject to the standard.

5. *An existing transmission line operated below 200kV which is newly acquired by an asset owner and which was not previously subject to this standard becomes subject to this standard 12 months after the acquisition date of the line if at the time of acquisition the line is designated by the Planning Coordinator as an element of an IROL or by WECC as an element of a Major WECC Transfer Path.*

Case 5 is needed because an existing line that is operated below 200 kV can be acquired by a Transmission Owner from a third party such as a Distribution Provider or other end-user who was using the line solely for local distribution purposes, but the Transmission owner, upon acquisition, is incorporating the line into the interconnected electrical energy transmission network. In this special case the line upon acquisition was designated as an element of an Interconnection Reliability Operating Limit (IROL) or an element of a Major WECC transfer Path.

Definition of Terms

Right-of-Way (ROW)*

The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.

The current glossary definition of this NERC term is modified to address the issues set forth in Paragraph 734 of FERC Order 693.

The current NERC glossary definition of Right of Way has been modified to address the matter set forth in Paragraph 734 of FERC Order 693. The Order pointed out that Transmission Owners may in some cases own more property or rights than are needed to reliably operate transmission lines. This modified definition represents a slight but significant departure from the strict legal definition of "right of way" in that this definition is based on engineering and construction considerations that establish the width of a corridor from a technical basis. The pre-2007 maintenance records are included to allow the use of such vegetation widths if there were no engineering or construction standards that referenced the width of right of way to be maintained for vegetation on a particular line but the evidence exists in maintenance records for a width that was in fact maintained prior to this standard becoming mandatory. Such widths may be the only information available for lines that had limited or no vegetation easement rights and were typically maintained primarily to ensure public safety. This standard does not require additional easement rights to be purchased to satisfy a minimum right of way width that did not exist prior to this standard becoming mandatory.

This definition does not imply that danger tree rights beyond the constructed and maintained width are incorporated in the definition; therefore fall-ins from outside the ROW but within an area with danger tree rights would not be considered fall-ins from within the ROW.

Vegetation Inspection*

The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.

The inspection includes the identification of any vegetation that may pose a threat to reliability

The current glossary definition of this NERC term is modified to allow both maintenance inspections and vegetation inspections to be performed concurrently.

Current definition of Vegetation Inspection: The systematic examination of a transmission corridor to document vegetation conditions.

prior to the next planned maintenance or inspection work, considering the current location of the conductor and other possible locations of the conductor due to sag and sway for rated conditions.

This definition allows both maintenance inspections and vegetation inspections to be performed concurrently.

* This is a modification to a defined term in the NERC glossary and will be incorporated into the NERC glossary of terms with final approval of this standard revision.

See the Guidelines and Technical Basis section on Requirement R6 contained within the Standard for more details on inspections.

Minimum Vegetation Clearance Distance (MVCD)

The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.

The MVCD is a calculated minimum distance that is derived from the Gallet Equations. This is a method has been in the design of high voltage transmission lines. Keeping vegetation away from high voltage conductors by this distance will prevent voltage flash-over to the vegetation. See the explanatory text below for Requirement R3 and associated Figures 1, 2 and 3. Details of the equations and an example calculation are provided in Appendix 1below of the Technical Reference document. Table 1in Appendix 1 below provides MVCD values for various voltages and altitudes.

Applicability of the Standard

4. Applicability

4.1. ***Functional Entities:***
Transmission Owners

4.2. ***Facilities:*** *Defined below (referred to as "applicable lines"), including but not limited to those that cross lands owned by federal*[1]*, state, provincial, public, private, or tribal entities:*

4.2.1 *Each overhead transmission lines operated at 200kV or higher.*

4.2.2 *Each overhead transmission lines operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator.*

4.2.3 *Each overhead transmission lines operated below 200 kV identified as an element of a Major WECC Transfer Paths in the Bulk Electric System by WECC.*

4.2.4 Each overhead transmission line identified above (4.2.1 through 4.2.3) located outside the fenced area of the switchyard, station or substation and any portion of the span *of the transmission line that is crossing the substation fence.*

4.3. ***Enforcement:*** *The reliability obligations of the applicable entities and facilities are contained within the technical requirements of this standard*

Rationale

The areas excluded in 4.2.4 were excluded based on comments from industry for reasons summarized as follows: 1) There is a very low risk from vegetation in this area. Based on an informal survey, no TOs reported such an event. 2) Substations, switchyards, and stations have many inspection and maintenance activities that are necessary for reliability. Those existing process manage the threat. As such, the formal steps in this standard are not well suited for this environment. 3) NERC has a project in place to address at a later date the applicability of this standard to Generation Owners. 4) Specifically addressing the areas where the standard does and does not apply makes the standard clearer.

In Order 693, FERC discussed the 200 kV bright-line test of applicability. While FERC did not change the 200 kV bright-line, the Commission remained concerned that there may be some transmission lines operating at lesser voltages that could have significant impact on the Bulk Electric System that should therefore be subject to this standard.

[1] EPAct 2005 section 1211c: *"Access approvals by Federal agencies".*

NERC Standard FAC-014 has the stated purpose, "*To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.*" FAC-014 requires Reliability Coordinators, Planning Coordinators, and Transmission Planners to have a methodology to identify all lines that might comprise an IROL. Thus, these entities would identify sub-200 kV lines that qualify as part of an IROL and should be subject to FAC-003-2.

Although all three entities may prepare the list of elements, the list as provided by the Planning Coordinator function is the more appropriate choice for this Standard. The Time Horizon needed to plan vegetation management work does not lend itself to the operating horizon of a Reliability Coordinator. Additionally, the Planning Coordinator has a wider-area view than the Transmission Planner and could thus identify any elements of importance to a sub-set of its area that might be missed by a Transmission Planner.

Transmission Owners, who do not already get the list of circuits included in the definition of an IROL, can get them from the Planning Coordinator. Specifically R5 of FAC-014 specifies that "*The Reliability Coordinator, Planning Authority (Coordinator) and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits*"

Vegetation-related Sustained Outages that occur due to natural disasters are beyond the control of the Transmission Owner. These events are not classified as vegetation-related Sustained Outages and are therefore exempt from the Standard. Transmission lines are not designed to withstand the impacts of natural disasters such as flood, drought, earthquake, major storms, fire, hurricane, tornado, landslides, ice storms, etc. In the aftermath of catastrophic system damage from natural disasters the Transmission Owner's focus is on electric system restoration for public safety and critical support infrastructure.

Sustained Outages due to human or animal activity are beyond the control of the Transmission Owner. These outages are not classified as vegetation-related Sustained Outages and are therefore exempt from the Standard. Examples of these events may include new plantings by outside parties of tall vegetation under the transmission line planted since the last Vegetation Inspection, tree contacts with line initiated by vehicles, logging activities, etc.

The foregoing exemptions are addressed in a new footnote 2. Referred to collectively as force majeure events and activities, this footnote applies to requirements R1 and R2 in FAC-003-2.

The reliability objective of this NERC Vegetation Management Standard ("Standard") is to prevent vegetation-related outages which could lead to Cascading by effective vegetation maintenance while recognizing that certain outages such as those due to vandalism, human errors and acts of nature are not preventable. Operating experience clearly indicates that trees that have grown out of specification could contribute to a cascading grid failure, especially under heavy electrical loading conditions.

Serious outages and operational problems have resulted from interference between overgrown vegetation and transmission lines located on many types of lands and ownership situations. To properly reduce and manage this risk, it is necessary to apply the Standard to applicable lines on any kind of land or easement, whether they are Federal Lands, state or provincial lands, public or private lands, franchises, easements or lands owned in fee. For the purposes of the Standard and this Technical Reference document, the term “public lands” includes municipal lands, village lands, city lands, and land owned by a host of other governmental entities.

The Standard addresses vegetation management along applicable overhead lines that serve to connect one electric station to another. However, it is not intended to be applied to lines sections inside the electric station fence or other boundary of an electric station, submarine or underground lines.

The Standard is intended to reduce the risk of Cascading involving vegetation. It is not intended to prevent customer outages from occurring due to tree contact with all transmission lines and voltages. For example, localized customer service might be disrupted if vegetation were to make contact with a 69kV transmission line supplying power to a 12kV distribution station. However, this Standard is not written to address such isolated situations which have little impact on the overall Bulk Electric System.

Vegetation growth is constant and always present. Unmanaged vegetation below numerous transmission lines that are operating at or near their Rating is highly problematic. This situation has led to multiple subsequent line failures and Cascading. Conversely, most other outage causes (such as trees falling into lines, lightning, animals, motor vehicles, etc.) are statistically intermittent. These events are not any more likely to occur during heavy system loads than any other time. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures. Thus, this Standard’s emphasis is on vegetation grow-ins.

In preparing the original vegetation management standard in 2005, industry stakeholders set the threshold for applicability of the standard at 200kV. This was because an unexpected loss of lines operating at above 200kV has a higher probability of initiating a widespread blackout or cascading outages compared with lines operating at less than 200kV.

The original NERC Standard FAC-003-1 also allowed for application of the standard to “critical” circuits (critical from the perspective of initiating widespread blackouts or cascading outages) operating below 200kV. While the percentage of these circuits is relatively low, it remains a fact that there are sub-200kV circuits whose loss could contribute to a widespread outage. Given the very limited exposure and unlikelihood of a major event related to these lower-voltage lines, it would be an imprudent use of resources to apply the Standard to all sub-200kV lines. The drafting team, after evaluating several alternatives, selected the IROL and WECC Major Transfer Path criteria to determine applicable lines below 200 kV that are subject to this standard.

Requirements R1 and R2

R1. Each Transmission Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[2]:

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage[3],
2. An encroachment due to a fall-in from inside the Right-of-Way (ROW) that caused a vegetation-related Sustained Outage[4],
3. An encroachment due to the blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[4],
4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage[4].

R2. Each Transmission Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer

Rationale for R1 and R2:

Lines with the highest significance to reliability are covered in R1; all other lines are covered in R2.

Rationale for the types of failure to manage vegetation which are listed in order of increasing degrees of severity in non-compliant performance as it relates to a failure of a Transmission Owner's vegetation maintenance program:

1. This management failure is found by routine inspection or Fault event investigation, and is normally symptomatic of unusual conditions in an otherwise sound program.

2. This management failure occurs when the height and location of a side tree within the ROW is not adequately addressed by the program.

3. This management failure occurs when side growth is not adequately addressed and may be indicative of an unsound program.

4. This management failure is usually indicative of a program that is not addressing the most fundamental dynamic of vegetation management, (i.e. a grow-in under the line). If this type of failure is pervasive on multiple lines, it provides a mechanism for a Cascade.

[2] This requirement does not apply to circumstances that are beyond the control of a Transmission Owner subject to this reliability standard, including natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods; human or animal activity such as logging, animal severing tree, vehicle contact with tree, or installation, removal, or digging of vegetation. Nothing in this footnote should be construed to limit the Transmission Owner's right to exercise its full legal rights on the ROW.

[3] If a later confirmation of a Fault by the Transmission Owner shows that a vegetation encroachment within the MVCD has occurred from vegetation within the ROW, this shall be considered the equivalent of a Real-time observation.

[4] Multiple Sustained Outages on an individual line, if caused by the same vegetation, will be reported as one outage regardless of the actual number of outages within a 24-hour period.

Path; operating within its Rating and all Rated Electrical Operating Conditions of the types shown below[2]:

1. An encroachment into the MVCD as shown in FAC-003-Table 2, observed in Real-time, absent a Sustained Outage[3],
2. An encroachment due to a fall-in from inside the ROW that caused a vegetation-related Sustained Outage[4],
3. An encroachment due to blowing together of applicable lines and vegetation located inside the ROW that caused a vegetation-related Sustained Outage[4],
4. An encroachment due to vegetation growth into the MVCD that caused a vegetation-related Sustained Outage[4]

M1. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R1. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R1)

M2. Each Transmission Owner has evidence that it managed vegetation to prevent encroachment into the MVCD as described in R2. Examples of acceptable forms of evidence may include dated attestations, dated reports containing no Sustained Outages associated with encroachment types 2 through 4 above, or records confirming no Real-time observations of any MVCD encroachments. (R2)

R1 and R2 are performance-based requirements. The reliability objective or outcome to be achieved is the prevention of vegetation encroachments within a minimum distance of transmission lines. Content-wise, R1 and R2 are the same requirements; however, they apply to different Facilities. Both R1 and R2 require each Transmission Owner to manage vegetation to prevent encroachment within the MVCD of transmission lines. R1 is applicable to lines that are identified as an element of an IROL or Major WECC transfer path. R2 is applicable to all other lines that are <u>not</u> an element of an IROL, and <u>not</u> an element of a Major WECC Transfer Path.

The separation of applicability (between R1 and R2) recognizes that inadequate vegetation management for an applicable line that is an element of an IROL or Major WECC Transfer Path is a greater risk to the interconnected electric transmission system than applicable lines that are not an element of an IROL or a Major WECC Transfer Path. Applicable lines that are not an element of an IROL or Major WECC Transfer Path do require effective vegetation management, but these lines are comparatively less operationally significant. As a reflection of this difference in risk impact, the Violation Risk Factors (VRFs) are assigned as High for R1 and Medium for R2.

R1 and R2 state that if vegetation encroaches within the distances in Table 1 in Appendix 1 of this supplemental Technical Reference document, it is in violation of the standard. Table 1below, which is the same as Table 2 in the standard, tabulates the distances necessary to prevent spark-over based on the Gallet equations as described more fully in Appendix 1 below.

These requirements assume that transmission lines and their conductors are operating within their Rating. If a line conductor is intentionally or inadvertently operated beyond its Rating and Rated Electrical Operating Condition (potentially in violation of other standards), the occurrence of a clearance encroachment may occur solely due to that condition. For example, emergency actions taken by a Transmission Operator or Reliability Coordinator to protect an Interconnection may cause excessive sagging and an outage. Another example would be ice loading beyond the line's Rating and Rated Electrical Operating Condition. Such vegetation-related encroachments and outages are not violations of this standard.

Evidence of failures to adequately manage vegetation include real-time observation of a vegetation encroachment into the MVCD (absent a Sustained Outage), or a vegetation-related encroachment resulting in a Sustained Outage due to a fall-in from inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to the blowing together of the lines and vegetation located inside the ROW, or a vegetation-related encroachment resulting in a Sustained Outage due to a grow-in. Faults which do not cause a Sustained outage and which are confirmed to have been caused by vegetation encroachment within the MVCD are considered the equivalent of a Real-time observation for violation severity levels.

With this approach, the VSLs for R1 and R2 are structured such that they directly correlate to the severity of a failure of a Transmission Owner to <u>manage</u> vegetation and to the corresponding performance level of the Transmission Owner's vegetation program's ability to meet the objective of "preventing the risk of those vegetation related outages that could lead to Cascading." Thus violation severity increases with a Transmission Owner's inability to meet this goal and its potential of leading to a Cascading event. The additional benefits of such a combination are that it simplifies the standard and clearly defines performance for compliance. A performance-based requirement of this nature will promote high quality, cost effective vegetation management programs that will deliver the overall end result of improved reliability to the system.

Multiple Sustained Outages on an individual line can be caused by the same vegetation. For example initial investigations and corrective actions may not identify and remove the actual outage cause then another outage occurs after the line is re-energized and previous high conductor temperatures return. Such events are considered to be a single vegetation-related Sustained Outage under the standard where the Sustained Outages occur within a 24 hour period.

The MVCD is a calculated minimum distance stated in feet (or meters) to prevent spark-over, for various altitudes and operating voltages that is used in the design of Transmission Facilities. Keeping vegetation from entering this space will prevent transmission outages.

If the TO has applicable lines operated at nominal voltage levels not listed in Table 2, then the TO should use the next largest clearance distance based on the next highest nominal voltage in the table to determine an acceptable distance.

Requirement R3

> **Rationale**
>
> The documentation provides a basis for evaluating the competency of the Transmission Owner's vegetation program. There may be many acceptable approaches to maintain clearances. Any approach must demonstrate that the Transmission Owner avoids vegetation-to-wire conflicts under all Rated Electrical Operating Conditions. See Figure 1 for an illustration of possible conductor locations.

R3. *Each Transmission Owner shall have documented maintenance strategies or procedures or processes or specifications it uses to prevent the encroachment of vegetation into the MVCD of its applicable transmission lines that accounts for the following:*

3.1 *Movement of applicable line conductors under their Facility Rating and all Rated Electrical Operating Conditions;*

3.2 *Inter-relationships between vegetation growth rates, vegetation control methods, and inspection frequency.*

M3. *The maintenance strategies or procedures or processes or specifications provided demonstrate that the Transmission Owner can prevent encroachment into the MVCD considering the factors identified in the requirement. (R3)*

Requirement R3 is a competency based requirement concerned with the maintenance strategies, procedures, processes, or specifications, a Transmission Owner uses for vegetation management.

An adequate transmission vegetation management program formally establishes the approach the Transmission Owner uses to plan and perform vegetation work to prevent transmission Sustained Outages and minimize risk to the transmission system. The approach provides the basis for evaluating the intent, allocation of appropriate resources and the competency of the Transmission Owner in managing vegetation. There are many acceptable approaches to manage vegetation and avoid Sustained Outages. However, the Transmission Owner must be able to show the documentation of its approach and how it conducts work to maintain clearances.

An example of one approach commonly used by industry is ANSI Standard A300, part 7.

However, regardless of the approach a utility uses to manage vegetation, any approach a Transmission Owner chooses to use will generally contain the following elements:

1. *the maintenance strategy used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that MVCD clearances are never violated.*
2. *the work methods that the Transmission Owner uses to control vegetation*
3. *a stated Vegetation Inspection frequency*

4. *an annual work plan*

The conductor's position in space at any point in time is continuously changing in reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading. The movement of the transmission line conductor and the MVCD is illustrated in Figures 1, 2, and 3 below.

Conductor Dynamics

In order for a Transmission Owner to develop a specific maintenance approach, it is important to understand the dynamics of a line conductor's movements. This paper will first address the complexities inherent in observing and predicting conductor movement, particularly for field personnel. It will then present some examples of maintenance approaches which Transmission Owners may consider that take into account these complexities, and the practical approaches that can be utilized by field personnel.

Additionally, it is important the Transmission Owner consider all conductor locations, the MVCD, and vegetation growth between maintenance activities when developing a maintenance approach.

Understanding Conductor Position and Movement

The conductor's position in space at any point in time is continuously changing as a reaction to a number of different loading variables. Changes in vertical and horizontal conductor positioning are the result of thermal and physical loads applied to the line. Thermal loading is a function of line current and the combination of numerous variables influencing ambient heat dissipation including wind velocity/direction, ambient air temperature and precipitation. Physical loading applied to the conductor affects sag and sway by combining physical factors such as ice and wind loading.

As a consequence of these loading variables, the conductor's position in space is dynamic and moving. When calculating the range of conductor positions, the Transmission Owner should use the same design criteria and assumptions that are used to establish Ratings and System Operating Limits (SOLs), as described in other standards. Typically, the greatest conductor movements occur at mid-span. As the conductor moves through various positions, a spark-over zone surrounding the conductor moves with it. The radius of the spark-over zone may be found by referring to Table 1 below. For illustrations of this zone and conductor movements, Figures 1, 2 and 3 below are provided. At the time of making a field observation, however, it is very difficult to precisely know where the conductor is in relation to its wide range of all possible positions. Therefore, Transmission Owners must adopt maintenance approaches that account for this dynamic situation.

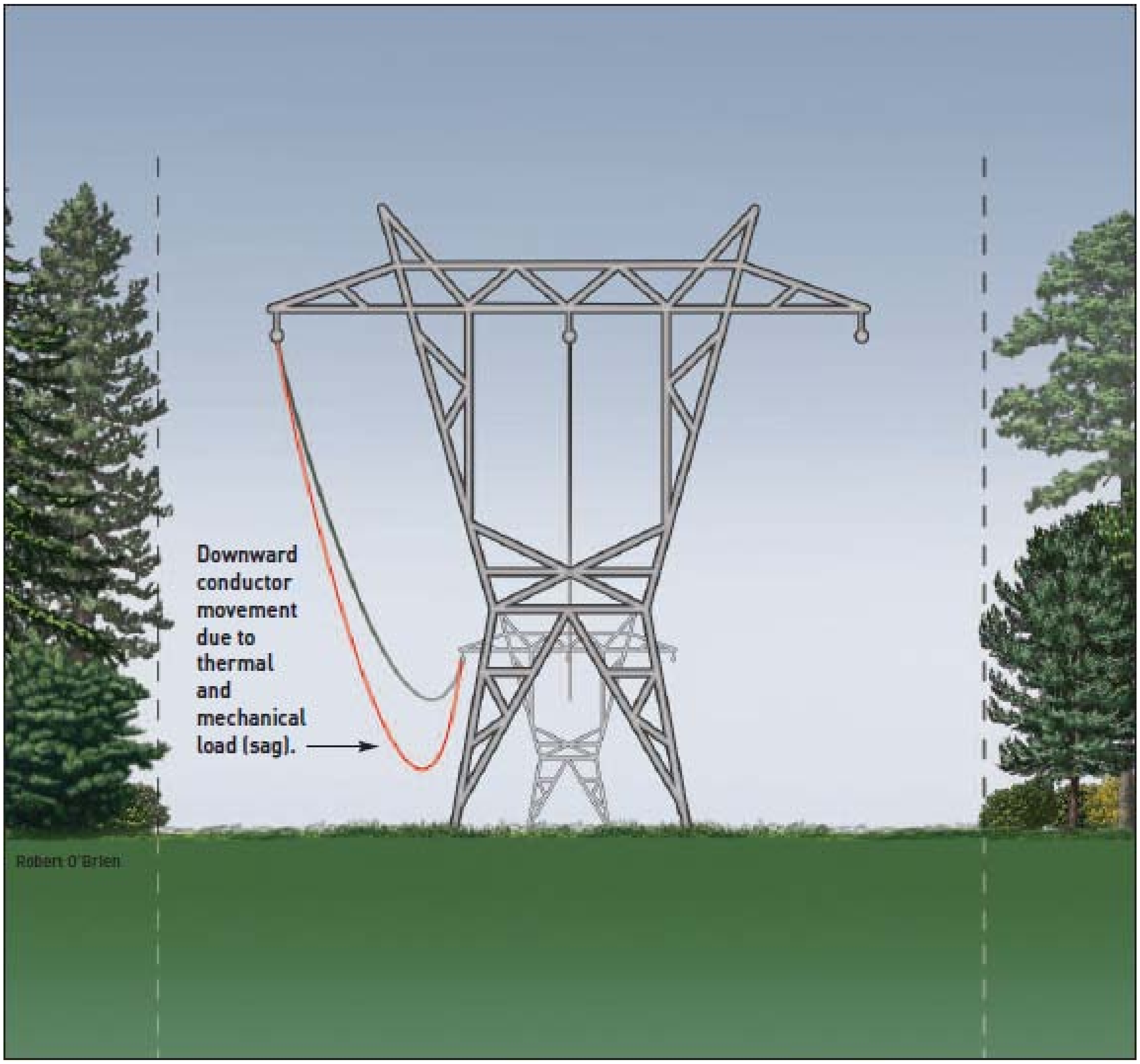
Downward conductor movement due to thermal and mechanical load (sag).
Robert O'Brien

Figure 1

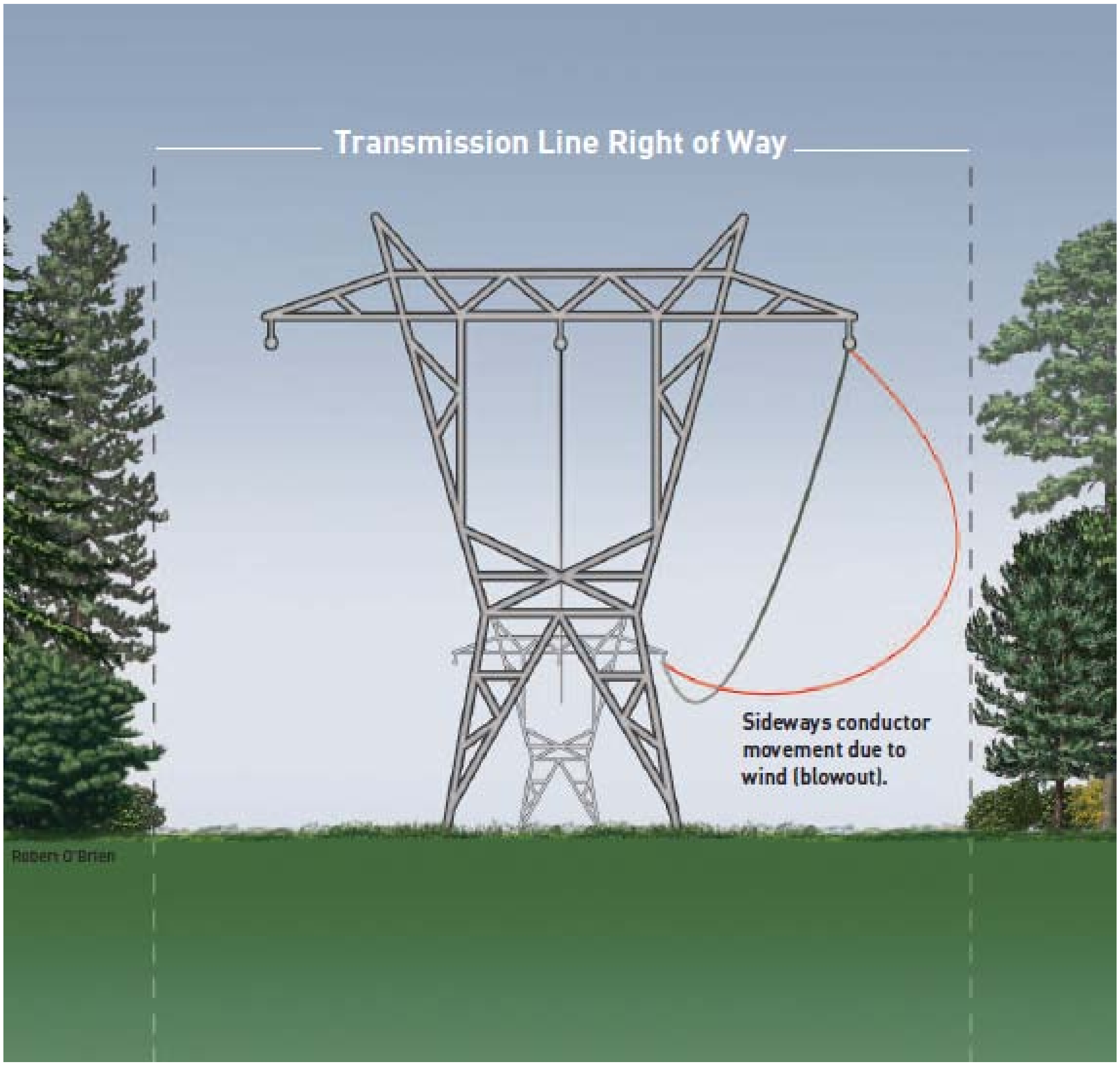
Transmission Line Right of Way
Sideways conductor
movement due to
wind (blowout).
Robert O'Brien

Figure 2

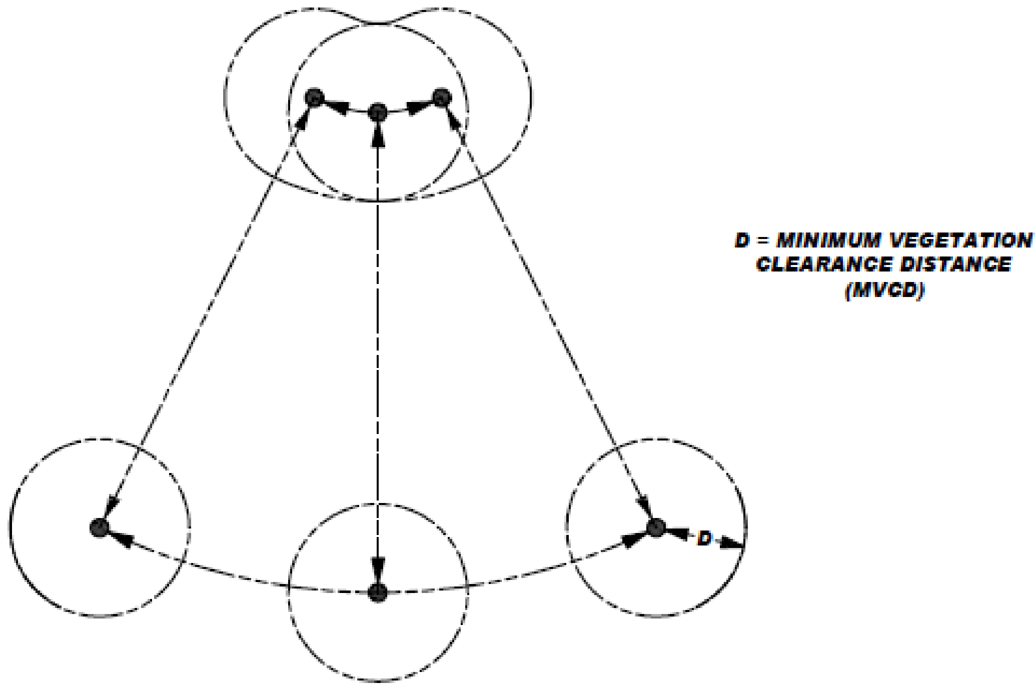

Figure 3

A cross-section view of a single conductor at a given point along the span is shown with six possible conductor positions due to movement resulting from thermal and mechanical loading.

Selecting a Maintenance Approach

In order to maintain adequate separation between vegetation and transmission line conductors, the Transmission Owner must craft a maintenance strategy that keeps vegetation well away from the spark-over zone mentioned above. In fact, it is generally necessary to incorporate a variety of maintenance strategies. For example, one Transmission Owner may utilize a combination of routine cycles, traditional IVM techniques and long-term planning. Another Transmission Owner may place a higher reliance on frequent inspections and follow-up remediation as opposed to a set cyclical approach. This variation of approaches is further warranted when factors, such as terrain, vegetation types, weather and climate, and any, environmental, legal or other land use constraints, must be considered in developing a Transmission Owner's specific approach to satisfying R3.

The following describes some strategies which may be utilized by a Transmission Owner. A Transmission Owner's basic maintenance approach in relatively flat terrain could be to remove all incompatible vegetation from the ROW if it has the right to do so and has no constraints. In mountainous terrain, however, this strategy could change to managing vegetation based on vegetation-to-conductor clearances, since it might not be necessary to remove vegetation in a valley that is far below the conductors at maximum sag.

If faced with easement constraints on a line design with sufficient ground clearance, the approach could be to allow vegetation such as fruit trees, but only up to a given height at maturity (for example 10 feet from the ground). If constraints cannot be overcome and if design clearances are sufficient, an exception to the Transmission Owner's 10-foot guideline might be made. If an approach is chosen to manage vegetation based primarily on clearance distances it could include an inspection regimen to regularly ensure that impending clearance problems are identified early for rectification.

ANSI A300 – Best Management Practices for Tree Care Operations

A description of ANSI A-300, part 7, is offered below to illustrate another maintenance approach that could be used in developing a comprehensive transmission vegetation management program.

Introduction

Integrated Vegetation Management (IVM) is a best management practice conveyed in the American National Standard for Tree Care Operations, Part 7 (ANSI 2006) and the International Society of Arboriculture *Best Management Practices: Integrated Vegetation Management* (Miller 2007). IVM is consistent with the requirements in FAC-003-02, and it provides practitioners with what industry experts consider to be appropriate techniques to apply to electric right-of-way projects in order to meet or exceed the Standard.

IVM is a system of managing plant communities whereby managers set objectives; identify compatible and incompatible vegetation; consider action thresholds; and evaluate, select and implement the most appropriate control method or methods to achieve set objectives. The choice of control method or methods should be based on the environmental impact and anticipated effectiveness; along with site characteristics, security, economics, current land use and other factors.

Planning and Implementation

Best management practices provide a systematic way of planning and implementing a vegetation management program. While designed primarily with transmission systems in mind, it is also applicable to distribution projects. As presented in ANSI A300 part 7 and the ISA best management practices, IVM consists of 6 elements:

1) Set Objectives
2) Evaluate the Site
3) Define Action Thresholds
4) Evaluate and Select Control Methods
5) Implement IVM
6) Monitor Treatment and Quality Assurance

The setting of objectives, defining action thresholds, and evaluating and selecting control methods all require decisions. The planning and implementation process is cyclical and continuous, because vegetation is dynamic and managers must have the flexibility to adjust their plans. Adjustments may be made at each stage as new information becomes available and circumstances evolve.

Set Objectives

Objectives should be clearly defined and documented. Examples of objectives can include promoting safety, preventing sustained outages caused by vegetation growing into electric facilities, maintaining regulatory compliance, protecting structures and security, restoring electric service during emergencies, maintaining access and clear lines of sight, protecting the environment, and facilitating cost effectiveness. Objectives should be based on site factors, such as workload and vegetation type, in addition to human, equipment and financial resources. They will vary from utility to utility and project to project, depending on line voltage and criticality, as well as topographical, environmental, fiscal and political considerations. However, where it is appropriate, the overriding focus should be on environmentally-sound, cost effective control of species that potentially conflict with the electric facility, while promoting compatible, early successional, sustainable plant communities.

Work Load Evaluations

Work-load evaluations are inventories of vegetation that could have a bearing on management objectives. Work load assessments can capture a variety of vegetation characteristics, such as location, height, species, size and condition, hazard status, density and clearance from conductors. Assessments should be conducted considering voltage, conductor sag from ambient temperatures and loading, and the potential influence of wind on line sway.

Evaluate and Select Control Methods

Control methods are the process through which managers achieve objectives. The most suitable control method best achieves management objectives at a particular site. Many cases call for a combination of methods. Managers have a variety of controls from which to choose, including manual, mechanical, herbicide and tree growth regulators, biological, and cultural options.

Manual Control Methods

Manual methods employ workers with hand-carried tools, including chainsaws, handsaws, pruning shears and other devices to control incompatible vegetation. The advantage of manual techniques is that they are selective and can be used where others may not be. On the other hand, manual techniques can be inefficient and expensive compared to other methods.

Mechanical Control Methods

Mechanical controls are done with machines. They are efficient and cost effective, particularly for clearing dense vegetation during initial establishment, or reclaiming neglected or overgrown right of way. On the other hand, mechanical control methods can be non-selective and disturb sensitive sites.

Tree Growth Regulator and Herbicide Control Methods

Tree growth regulators and herbicides can be effective for vegetation management. Tree growth regulators (TGRs) are designed to reduce growth rates by interfering with natural plant processes. TGRs can be helpful where removals are prohibited or impractical by reducing the growth rates of some fast-growing species.

Herbicides control plants by interfering with specific botanical biochemical pathways. Herbicide use can control individual plants that are prone to re-sprout or sucker after removal. When trees that re-sprout or sucker are removed without herbicide treatment, dense thickets develop, impeding access, swelling workloads, increasing costs, blocking lines-of-site, and deteriorating wildlife habitat. Treating suckering plants allows early successional, compatible species to dominate the right-of-way and out-compete incompatible species, ultimately reducing work.

Cultural Control Methods

Cultural methods modify habitat to discourage incompatible vegetation and establish and manage desirable, early successional plant communities. Cultural methods take advantage of seed banks of native, compatible species lying dormant on site. In the long run, cultural control is the most desirable method where it is applicable.

A cultural control known as cover-type conversion provides a competitive advantage to short-growing, early successional plants, allowing them to thrive and eventually out-compete unwanted tree species for sunlight, essential elements and water. The early successional plant community is relatively stable, tree-resistant and reduces the amount of work, including herbicide application, with each successive treatment.

Wire-Border Zone

The wire-border zone technique is a management philosophy that can be applied through cultural control. W.C. Bramble and W.R. Byrnes developed it in the mid-1980s out of research begun in 1952 on a transmission right-of-way in the Pennsylvania State Game Lands 33 Research and Demonstration project (Yahner and Hutnik (2004).

The wire zone is the section of a utility transmission right-of-way directly under the wires and extending outward about 10 feet on each side. The wire zone is managed to promote a low-growing plant community dominated by grasses, herbs and small shrubs (under 3 feet in height at maturity). The border zone is the remainder of the right-of-way. It is managed to establish small trees and tall shrubs (under 25 feet in height at maturity). When properly managed, diverse, tree-resistant plant communities develop in wire and border zones. The communities not only protect the electric facility and reduce long-term maintenance, but also enhance wildlife habitat, forest ecology and aesthetic values.

Although the wire-border zone is a best practice in many instances, it is not necessarily universally suitable. For example, standard wire-border zone prescriptions may be unnecessary where lines are high off the ground, such as across low valleys or canyons, so the technique can be modified without sacrificing reliability.

One way to accommodate variances in topography is to establish different regions based on wire height. For example, over canyon bottoms or other areas where conductors are 100 feet or more above the ground, only a few trees are likely to be tall enough to conflict with the lines. In those cases, trees that potentially interfere with the transmission lines can be removed selectively on a case-by-case basis.

In areas where the wire is lower, perhaps between 50-100 feet from the ground, a border zone community can be developed throughout the right-of-way. Note that in many cases, conductor attachment points are more than 50 feet off the ground, so a border zone community can be cultivated near structures. Where the line is less than 50 feet off the ground, managers could apply a full wire-border zone prescription.

An environmental advantage of this type of modification is stream protection. Streams often course through the valleys and canyons where lines are likely to be elevated. Leaving timber or border zone communities in canyon bottoms helps shelter this valuable habitat, enabling managers to achieve environmentally sensitive objectives.

Implement IVM

All laws and regulations governing IVM practices and specifications written by qualified vegetation managers must be followed. Integrated vegetation management control methods should be implemented on regular work schedules, which are based on established objectives and completed assessments. Work should progress systematically, using control measures determined to be best for varying conditions at specific locations along a right-of-way. Some considerations used in developing schedules include the importance and type of line, vegetation clearances, workloads, growth rate of predominant vegetation, geography, accessibility, and in some cases, time lapsed since the last scheduled work.

Clearances Following Work

Clearances following work should be sufficient to meet management objectives, including preventing trees from entering the Minimum Vegetation Clearance Distance, electric safety risks, service-reliability threats and cost.

Monitor Treatment and Quality Assurance

An effective program includes documented processes to evaluate results. Evaluations can involve quality assurance while work is underway and after it is completed. Monitoring for quality assurance should begin early to correct any possible miscommunication or misunderstanding on the part of crewmembers. Early and consistent observation and evaluation also provides an opportunity to modify the plan, if need be, in time for a successful outcome.

Utility vegetation management programs should have systems and procedures in place for documenting and verifying that vegetation management work was completed to specifications. Post-control reviews can be comprehensive or based on a statistically representative sample. This final review points back to the first step and the planning process begins again.

Summary of A-300 example

Integrated Vegetation Management offers among others, a systematic way of planning and implementing a vegetation management program as presented in ANSI A300 Part 7. This methodology enables a program to comply with the NERC *Transmission Vegetation Management Program* standard (FAC-003-2). Managers should select control options to best promote management objectives.

Vegetation Inspections

The standard in R6 establishes the frequency of vegetation inspections. These inspections can be used to “evaluate the site” as referred to in the second element of ANSI A300 Part 7. This necessary frequency may need to be less than the annually based on anticipated growth rates of the local vegetation, length of the growing season for the geographical area, limited ROW width, rainfall amounts, etc.

Annual Work Plan

Requirement R7 of the Standard addresses the execution of the annual work plan. A comprehensive approach that exercises the full extent of legal rights is superior to incremental management in the long term because it reduces overall encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient at all locations on the ROW. Removal is superior to pruning. Removal minimizes the possibility of conflicts between energized conductors and vegetation. When this is not possible, the approach should be to use vegetation maintenance methods to work towards or achieve the maximum use of the ROW.

Requirement R4

R4. *Each Transmission Owner, without any intentional time delay, shall notify the control center holding switching authority for the associated applicable transmission line when the Transmission Owner has confirmed the existence of a vegetation condition that is likely to cause a Fault at any moment.*

Rationale

This is to ensure expeditious communication between the Transmission Owner and the control center when a critical situation is confirmed.

M4. *Each Transmission Owner that has a confirmed vegetation condition likely to cause a Fault at any moment will have evidence that it notified the control center holding switching authority for the associated transmission line without any intentional time delay. Examples of evidence may include control center logs, voice recordings, switching orders, clearance orders and subsequent work orders. (R4)*

R4 is a risk-based requirement. It focuses on preventative actions to be taken by the Transmission Owner for the mitigation of Fault risk when a vegetation threat is confirmed. R4 involves the notification of potentially threatening vegetation conditions, without any intentional delay, to the control center holding switching authority for that specific transmission line. Examples of acceptable unintentional delays may include communication system problems (for example, cellular service or two-way radio disabled), crews located in remote field locations with no communication access, delays due to severe weather, etc.

Confirmation is key that a threat actually exists due to vegetation. This confirmation could be in the form of a Transmission Owner's employee who personally identifies such a threat in the field. Confirmation could also be made by sending out an employee to evaluate a situation reported by a landowner.

Vegetation-related conditions that warrant a response include vegetation that is near or encroaching into the MVCD (a grow-in issue) or vegetation that could fall into the transmission conductor (a fall-in issue). A knowledgeable verification of the risk would include an assessment of the possible sag or movement of the conductor while operating between no-load conditions and its rating.

The Transmission Owner has the responsibility to ensure the proper communication between field personnel and the control center to allow the control center to take the appropriate action until the vegetation threat is relieved. Appropriate actions may include a temporary reduction in the line loading, switching the line out of service, or positioning the system in recognition of the increasing risk of outage on that circuit. The notification of the threat should be communicated in terms of minutes or hours as opposed to a longer time frame for corrective action plans (see R5).

All potential grow-in or fall-in vegetation-related conditions will not necessarily cause a Fault at any moment. For example, some Transmission Owners may have a danger tree identification program that identifies trees for removal with the potential to fall near the line. These trees would not require notification to the control center unless they pose an immediate fall-in threat.

Requirement R5

R5. *When a Transmission Owner is constrained from performing vegetation work on an applicable line operating within their Rating and all Rated Electrical Operating Conditions, and the constraint may lead to a vegetation encroachment into the MVCD prior to the implementation of the next annual work plan, then the Transmission Owner shall take corrective action to ensure continued vegetation management to prevent encroachments.*

M5. *Each Transmission Owner has evidence of the corrective action taken for each constraint where an applicable transmission line was put at potential risk. Examples of acceptable forms of evidence may include initially-planned work orders, documentation of constraints from landowners, court orders, inspection records of increased monitoring, documentation of the de-rating of lines, revised work orders, invoices, or evidence that a line was de-energized. (R5)*

Rationale

Legal actions and other events may occur which result in constraints that prevent the Transmission Owner from performing planned vegetation maintenance work.

In cases where the transmission line is put at potential risk due to constraints, the intent is for the Transmission Owner to put interim measures in place, rather than do nothing.

The corrective action process is not intended to address situations where a planned work methodology cannot be performed but an alternate work methodology can be used.

R5 is a risk-based requirement. It focuses upon preventative actions to be taken by the Transmission Owner for the mitigation of Sustained Outage risk when temporarily constrained from performing vegetation maintenance. The intent of this requirement is to deal with situations that prevent the Transmission Owner from performing planned vegetation management work and, as a result, have the potential to put the transmission line at risk. Constraints to performing vegetation maintenance work as planned could result from legal injunctions filed by property owners, the discovery of easement stipulations which limit the Transmission Owner’s rights, or other circumstances.

This requirement is not intended to address situations where the transmission line is not at potential risk and the work event can be rescheduled or re-planned using an alternate work methodology. For example, a land owner may prevent the planned use of chemicals on non-threatening, low growth vegetation but agree to the use of mechanical clearing. In this case the Transmission Owner is not under any immediate time constraint for achieving the management objective, can easily reschedule work using an alternate approach, and therefore does not need to take interim corrective action.

However, in situations where transmission line reliability is potentially at risk due to a constraint, the Transmission Owner is required to take an interim corrective action to mitigate the potential risk to the transmission line. A wide range of actions can be taken to address various situations. General considerations include:

- Identifying locations where the Transmission Owner is constrained from performing planned vegetation maintenance work which potentially leaves the transmission line at risk.
- Developing the specific action to mitigate any potential risk associated with not performing the vegetation maintenance work as planned.
- Documenting and tracking the specific action taken for each location.
- In developing the specific action to mitigate the potential risk to the transmission line the Transmission Owner could consider location specific measures such as modifying the inspection and/or maintenance intervals. Where a legal constraint would not allow any vegetation work, the interim corrective action could include limiting the loading on the transmission line.
- The Transmission Owner should document and track the specific corrective action taken at each location. This location may be indicated as one span, one tree or a combination of spans on one property where the constraint is considered to be temporary.

Requirement R6

R6. *Each Transmission Owner shall perform a Vegetation Inspection of 100% of its applicable lines (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) at least once per calendar year and with no more than 18 months between inspections on the same ROW.*[5]

M6. *Each Transmission Owner has evidence that it conducted Vegetation Inspections of the transmission line ROW for all applicable lines at least once per calendar year but with no more than 18 months between inspections on the same ROW. Examples of acceptable forms of evidence may include completed and dated work orders, dated invoices, or dated inspection records. (R6)*

Rationale

Inspections are used by Transmission Owners to assess the condition of the entire ROW. The information from the assessment can be used to determine risk, determine future work and evaluate recently-completed work. This requirement sets a minimum Vegetation Inspection frequency of once per calendar year but with no more than 18 months between inspections on the same ROW. Based upon average growth rates across North America and on common utility practice, this minimum frequency is reasonable. Transmission Owners should consider local and environmental factors that could warrant more frequent inspections.

R6 is a risk-based requirement. This requirement sets a minimum time period for completing Vegetation Inspections that fits general industry practice. In addition, the fact that Vegetation Inspections can be performed in conjunction with general line inspections further facilitates a Transmission Owner's ability to meet this requirement. However, the Transmission Owner may determine that more frequent inspections are needed to maintain reliability levels, dependent upon such factors as anticipated growth rates of the local vegetation, length of the growing season for the geographical area, limited ROW width, and rainfall amounts. Therefore it is expected that some transmission lines may be designated with a higher frequency of inspections.

Footnote 5 is added to address the situation where a Transmission Owner through no fault of its own, would be unable to complete the vegetation inspection within the allotted time period. This would include the situation of mutual aid as well as disasters to the Transmission Owner's own system.

[5] When the Transmission Owner is prevented from performing a Vegetation Inspection within the timeframe in R6 due to a natural disaster, the TO is granted a time extension that is equivalent to the duration of the time the TO was prevented from performing the Vegetation Inspection.

The VSL for Requirement R6 has VSL categories ranked by the percentage of the required ROW inspections completed. To calculate the percentage of inspection completion, the Transmission Owner may choose units such as: line miles or kilometers, circuit miles or kilometers, pole line miles, ROW miles, etc.

For example, when a Transmission Owner operates 2,000 miles of applicable transmission lines this Transmission Owner will be responsible for inspecting all the 2,000 miles of lines at least once during the calendar year. If one of the included lines was 100 miles long, and if it was not inspected during the year, then the amount failed to inspect would be 100/2000 = 0.05 or 5%.

The "Low VSL" for R6 would apply in this example.

Requirement R7

R7. *Each Transmission Owner shall complete 100% of its annual vegetation work plan of applicable lines to ensure no vegetation encroachments occur within the MVCD. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made (provided they do not allow encroachment of vegetation into the MVCD) and must be documented. The percent completed calculation is based on the number of units actually completed divided by the number of units in the final amended plan (measured in units of choice - circuit, pole line, line miles or kilometers, etc.) Examples of reasons for modification to annual plan may include:*

- Change in expected growth rate/ environmental factors
- Circumstances that are beyond the control of a Transmission Owner[6]
- Rescheduling work between growing seasons
- Crew or contractor availability/ Mutual assistance agreements
- Identified unanticipated high priority work
- Weather conditions/Accessibility
- Permitting delays
- Land ownership changes/Change in land use by the landowner
- Emerging technologies

Rationale

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. It allows modifications to the planned work for changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors, provided that those modifications do not put the transmission system at risk of a vegetation encroachment.

M7. *Each Transmission Owner has evidence that it completed its annual vegetation work plan. Examples of acceptable forms of evidence may include a copy of the completed annual work plan (including modifications if any), dated work orders, dated invoices, or dated inspection records. (R7)*

R7 is a risk-based requirement. The Transmission Owner is required to implement its work plan for vegetation management to accomplish the purpose of this Standard. Modifications to the work plan in response to changing conditions or to findings from vegetation inspections may be made and documented provided they do not put the transmission system at risk. The annual

[6] Circumstances that are beyond the control of a Transmission Owner include but are not limited to natural disasters such as earthquakes, fires, tornados, hurricanes, landslides, ice storms, floods, or major storms as defined either by the TO or an applicable regulatory body.

work plan requirement is not intended to necessarily require a “span-by-span”, or even a “line-by-line” detailed description of all work to be performed. It is only intended to require that the Transmission Owner provide evidence of annual planning and execution of a vegetation management maintenance approach which successfully prevents encroachment of vegetation into the MVCD.

For example, when a Transmission Owner identifies 1,000 miles of applicable transmission lines to be completed in the TO’s annual plan, the Transmission Owner will be responsible completing those identified miles. If a TO makes a modification to the annual plan that does not put the transmission system at risk of an encroachment the annual plan may be modified. If 100 miles of the annual plan is deferred until next year the calculation to determine what percentage was completed for the current year would be: 1000 – 100 (deferred miles) = 900 modified annual plan, or 900 / 900 = 100% completed annual miles. If a TO only completed 875 of the total 1000 miles with no acceptable documentation for modification of the annual plan the calculation for failure to complete the annual plan would be: 1000 – 875 = 125 miles failed to complete then, 125 miles (not completed) / 1000 total annual plan miles = 12.5% failed to complete.

The ability to modify the work plan allows the Transmission Owner to change priorities or treatment methodologies during the year as conditions or situations dictate. For example recent line inspections may identify unanticipated high priority work, weather conditions (drought) could make herbicide application ineffective during the plan year, or a major storm could require redirecting local resources away from planned maintenance or work may be deferred to a subsequent year because of slower-than-expected growth. This situation may also include complying with mutual assistance agreements by moving resources off the Transmission Owner’s system to work on another system. Any of these examples could result in acceptable deferrals or additions to the annual work plan. Modifications to the annual work plan must always ensure the reliability of the electric Transmission system.

In general, the vegetation management maintenance approach should use the full extent of the Transmission Owner’s legal rights on the ROW. A comprehensive approach that exercises the full extent of legal rights on the ROW is superior to incremental management in the long term because it reduces the overall potential for encroachments, and it ensures that future planned work and future planned inspection cycles are sufficient.

When developing the annual work plan the Transmission Owner should allow time for procedural requirements to obtain permits to work on federal, state, provincial, public, tribal lands. In some cases the lead time for obtaining permits may necessitate preparing work plans more than a year prior to work start dates. Transmission Owners may also need to consider those special landowner requirements as documented in easement instruments.

This requirement sets the expectation that the work identified in the annual work plan will be completed as planned. Therefore, deferrals or relevant changes to the annual plan shall be documented. Depending on the planning and documentation format used by the Transmission Owner, evidence of successful annual work plan execution could consist of signed-off work orders, signed contracts, printouts from work management systems, spreadsheets of planned

versus completed work, timesheets, work inspection reports, or paid invoices. Other evidence may include photographs and walk-through reports.

Appendix 1: Clearance Distance Derivation by the Gallet Equation

The Gallet Equation is a well-known method of computing the required strike distance for proper insulation coordination, and has the ability to take into account various air gap geometries, as well as non-standard atmospheric conditions. When the Gallet Equation and conservative probabilistic methods are combined, i.e. deterministic design, spark-over probabilities of 10^{-6} or less are achieved. This approach is well known for its conservatism and was used to design the first 500 kV and 765 kV lines in North America [1]. Thus, the deterministic design approach using the Gallet Equation is used for the standard to compute the minimum strike distance between transmission lines and the vegetation that may be present in or along the transmission corridor.

Method Explanation (Gallet Equation)

In 1975 G. Gallet published a benchmark paper that provided a method to compute the critical flashover voltage (CFO) of various air gap geometries [4]. The Gallet Equation uses various "gap factors" to take into account various air gap geometries. Various gap factor values are provided in [1]. If the vegetation in a transmission corridor, e.g. a tree, is assumed electrically to be a large structure then the CFO of such an air gap geometry can be computed for dry or wet conditions using a well established equation proposed by Gallet [1],[2],[4],

$$CFO_A = k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} \qquad (1)$$

where,

k_w	is defined as the factor that takes into account wet or dry conditions (dry = 1.0 and wet = 0.96) and phase arrangement (multiply by 1.08 for outside phase), e.g. outside phase and wet conditions = (0.96)(1.08) = 1.037,
k_g	is defined as the gap factor (1.3 for conductor to large structure),
D	is the strike distance (m),
CFO_A	is the CFO for the relative air density (kV).
δ	is defined as the relative air density and is approximately equal to (2) where A is the altitude in km,

$$\delta = e^{-\frac{A}{8.6}} \qquad (2)$$

$$m = 1.25G_0\left(G_0 - 0.2\right) \qquad (3)$$

$$G_0 = \frac{CFO_s}{500 \cdot D} \qquad (4)$$

$$CFO_s = k_w \cdot k_g \cdot \frac{3400}{1 + \frac{8}{D}} \qquad (5)$$

where CFO_S is the CFO for standard atmospheric conditions (kV). Using (1)-(5), the required CFO_A can be computed using an iterative process.

Once the CFO_A is known, deterministic methods can be used to determine the required clearance distance. If we let the maximum switching overvoltage be equal to the withstand voltage of the air gap (CFO_A - 3σ) then the CFO_A can be written as (6).

$$CFO_A = \frac{V_m}{1 - 3\left(\frac{\sigma}{CFO_A}\right)} \qquad (6)$$

where

V_m is equal to the maximum switching overvoltage, i.e. the value that has a 0.135% chance of being exceeded,

σ is the standard deviation of the air gap insulation,

CFO_A is the critical flashover voltage of the air gap insulation under non-standard atmospheric conditions.

The ratio of σ to the CFO_A given in (6) can be assumed to be 0.05 (5%) [1]. Thus, (6) can be written as (7).

$$CFO_A = \frac{V_m}{0.85} \qquad (7)$$

Substituting (7) into (1) we arrive at (8).

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1 + \frac{8}{D}} \qquad (8)$$

Equation 8 relates the maximum transient overvoltage, V_m, to the air gap distance, *D*. Using (8) to compute the required clearance distance for the specified air gap geometry (conductor to large structure) results in a probability of flashover in the range of 10^{-6}.

Transient Overvoltage

In general, the worst case transient overvoltages occurring on a transmission line are caused by energizing or re-energizing the line with the latter being the extreme case if trapped charge is present. The intent of FAC-003 is to keep a transmission line that is *in service* from becoming de-energized (i.e. tripped out) due to sparkover from the line conductor to nearby vegetation. Thus, the worst case scenarios that are typically analyzed for insulation coordination purposes (e.g. line energization and re-energization) can be ignored. For the purposes of FAC-003-2, the worst case transient overvoltage then becomes the maximum value that can occur with the line energized. Determining a realistic value of transient overvoltage for this situation is difficult because the maximum transient overvoltage factors listed in the literature are based on a switching operation of the line in question. In other words, these maximum overvoltage values (e.g. the values listed in [2], [3] and [5]) are based on the assumption that the subject line is being energized, re-energized or de-energized. These operations, by their very nature, will create the largest transient overvoltages. Typical values of transient overvoltages of in-service lines, as such, are not readily available in the literature because the resulting level of overvoltage is negligible compared with the maximum (e.g. re-energizing a transmission line with trapped charge). A conservative value for the maximum transient overvoltage that can occur anywhere along the length of an in-service ac line is approximately 2.0 p.u.[2]. This value is a conservative estimate of the transient overvoltage that is created at the point of application (e.g. a substation) by switching a capacitor bank without a pre-insertion device (e.g. closing resistors). At voltage levels where capacitor banks are not very common (e.g. 362 kV), the maximum transient overvoltage of an “in-service” ac line are created by fault initiation on adjacent ac lines and shunt reactor bank switching. These transient voltages are usually 1.5 p.u. or less [2]. It is well known that these theoretical transient overvoltages will not be experienced at locations remote from the bus at which they were created; however, in order to be conservative, it will be assumed that all nearby ac lines are subjected to this same level of overvoltage. Thus, a maximum transient overvoltage factor of 2.0 p.u. for 302 kV and below and 1.4 p.u. for ac transmission lines 362 kV and above is used to compute the required clearance distances for vegetation management purposes.

The overvoltage characteristics of dc transmission lines vary somewhat from their ac counterparts. The referenced empirically derived transient overvoltage factor used to calculate the minimum clearance distances from dc transmission lines to vegetation for the purpose of FAC-003-2 will be 1.8 p.u.[3].

Example Calculation

An example calculation is presented below using the proposed method of computing the vegetation clearance distances. It is assumed that the line in question has a maximum operating voltage of 550 kV_{rms} line-to-line. Using a per unit transient overvoltage factor of 1.4, the result is a peak transient voltage of 629 kV_{crest}. It is further assumed that the line in question operates at a maximum altitude of 7000 feet (2.134 km) above sea level.

The required withstand voltage of the air gap must be equal to or greater than 629 kV_{crest}. Since the altitude is above sea level, (1) - (5) have to be iterated on to achieve the desired result. Equation (9) can be used as an initial guess for the clearance distance.

$$D_i = \frac{8}{\frac{3400 \cdot k_w \cdot k_g}{\left(\frac{V_m}{0.85}\right)} - 1} \tag{9}$$

For our case here, V_m is equal to 629 kV, k_w = 1.037 and k_g = 1.3. Thus,

$$D_i = \frac{8}{\frac{3400 \cdot k_w \cdot k_g}{\left(\frac{V_m}{0.85}\right)} - 1} = \frac{8}{\frac{3400 \cdot 1.037 \cdot 1.3}{\left(\frac{629}{0.85}\right)} - 1} = 1.535m \tag{10}$$

Using (2)-(5) and (8) the withstand voltage of the air gap is next computed. This value will then be compared to the maximum transient overvoltage.

$$CFO_S = k_w \cdot k_g \cdot \frac{3400}{1+\frac{8}{D}} = 1.037 \cdot 1.3 \cdot \frac{3400}{1+\frac{8}{1.535}} = 737.7kV \tag{11}$$

$$\delta = e^{-\frac{A}{8.6}} = e^{-\frac{2.134}{8.6}} = 0.78 \tag{12}$$

$$G_O = \frac{CFO_S}{500 \cdot D} = \frac{737.7}{(500) \cdot (1.535)} = 0.961 \tag{13}$$

$$m = 1.25 \cdot G_O(G_O - 0.2) = 1.25 \cdot 0.961(0.961 - 0.2) = 0.915 \tag{14}$$

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} = (0.85)(1.037)(1.3)(0.78)^{0.915}\left(\frac{3400}{1+\frac{8}{1.535}}\right) = 499.8kV \tag{15}$$

The calculated V_m is less than 629 kV; thus, the clearance distance must be increased. A few iterations using (2)-(5) and (8) are required until the computed $V_m \geq$ 629 kV. For this case it was found that D = 1.978 m (6.49 feet) yielded V_m = 629.3 kV. Using this clearance distance the following values were computed for the final iteration.

$$CFO_S = k_w \cdot k_g \cdot \frac{3400}{1+\frac{8}{D}} = 1.037 \cdot 1.3 \cdot \frac{3400}{1+\frac{8}{1.978}} = 908.5kV \tag{16}$$

$$\delta = e^{-\frac{A}{8.6}} = e^{-\frac{2.134}{8.6}} = 0.78 \tag{17}$$

$$G_O = \frac{CFO_S}{500 \cdot D} = \frac{908.5}{(500)\cdot(1.978)} = 0.919 \tag{18}$$

$$m = 1.25 \cdot G_O (G_O - 0.2) = 1.25 \cdot 0.919(0.919 - 0.2) = 0.825 \tag{19}$$

$$V_m = 0.85 \cdot k_w \cdot k_g \cdot \delta^m \cdot \frac{3400}{1+\frac{8}{D}} = (0.85)(1.037)(1.3)(0.78)^{0.825}\left(\frac{3400}{1+\frac{8}{1.978}}\right) = 629.3kV \tag{20}$$

Therefore, the minimum vegetation clearance distance for a maximum line to line ac operating voltage of 550 kV at 7000 feet above sea level is 1.978 m (6.49 feet). Table 1 provides calculated distances for various altitudes and maximum system operating ac voltages.

Table 1 — Minimum Vegetation Clearance Distances (MVCD)[7]

For **Alternating Current** Voltages (feet)

(AC) Nominal System Voltage (KV)	(AC) Maximum System Voltage (kV)[8]	MVCD (feet) Over sea level up to 500 ft	MVCD (feet) Over 500 ft up to 1000 ft	MVCD feet Over 1000 ft up to 2000 ft	MVCD feet Over 2000 ft up to 3000 ft	MVCD feet Over 3000 ft up to 4000 ft	MVCD feet Over 4000 ft up to 5000 ft	MVCD feet Over 5000 ft up to 6000 ft	MVCD feet Over 6000 ft up to 7000 ft	MVCD feet Over 7000 ft up to 8000 ft	MVCD feet Over 8000 ft up to 9000 ft	MVCD feet Over 9000 ft up to 10000 ft	MVCD feet Over 10000 ft up to 11000 ft
765	800	8.2ft	8.33ft	8.61ft	8.89ft	9.17ft	9.45ft	9.73ft	10.01ft	10.29ft	10.57ft	10.85ft	11.13ft
500	550	5.15ft	5.25ft	5.45ft	5.66ft	5.86ft	6.07ft	6.28ft	6.49ft	6.7ft	6.92ft	7.13ft	7.35ft
345	362	3.19ft	3.26ft	3.39ft	3.53ft	3.67ft	3.82ft	3.97ft	4.12ft	4.27ft	4.43ft	4.58ft	4.74ft
287	302	3.88ft	3.96ft	4.12ft	4.29ft	4.45ft	4.62ft	4.79ft	4.97ft	5.14ft	5.32ft	5.50ft	5.68ft
230	242	3.03ft	3.09ft	3.22ft	3.36ft	3.49ft	3.63ft	3.78ft	3.92ft	4.07ft	4.22ft	4.37ft	4.53ft
161*	169	2.05ft	2.09ft	2.19ft	2.28ft	2.38ft	2.48ft	2.58ft	2.69ft	2.8ft	2.91ft	3.03ft	3.14ft
138*	145	1.74ft	1.78ft	1.86ft	1.94ft	2.03ft	2.12ft	2.21ft	2.3ft	2.4ft	2.49ft	2.59ft	2.7ft
115*	121	1.44ft	1.47ft	1.54ft	1.61ft	1.68ft	1.75ft	1.83ft	1.91ft	1.99ft	2.07ft	2.16ft	2.25ft
88*	100	1.18ft	1.21ft	1.26ft	1.32ft	1.38ft	1.44ft	1.5ft	1.57ft	1.64ft	1.71ft	1.78ft	1.86ft
69*	72	0.84ft	0.86ft	0.90ft	0.94ft	0.99ft	1.03ft	1.08ft	1.13ft	1.18ft	1.23ft	1.28ft	1.34ft

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above).

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[7] The distances in this Table are the minimums required to prevent Flash-over; however prudent vegetation maintenance practices dictate that substantially greater distances will be achieved at time of vegetation maintenance.

[8] Where applicable lines are operated at nominal voltages other than those listed, The Transmission Owner should use the maximum system voltage to determine the appropriate clearance for that line.

Table 1 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[7]

For **Alternating Current** Voltages (meters)

(AC) Nominal System Voltage (KV)	(AC) Maximum System Voltage (kV)[8]	MVCD meters Over sea level up to 152.4m	MVCD meters Over 152.4m up to 304.8m	MVCD meters Over 304.8m up to 609.6m	MVCD meters Over 609.6m up to 914.4m	MVCD meters Over 914.4m up to 1219.2m	MVCD meters Over 1219.2m up to 1524m	MVCD meters Over 1524 m up to 1828.8m	MVCD meters Over 1828.8m up to 2133.6m	MVCD meters Over 2133.6m up to 2438.4m	MVCD meters Over 2438.4m up to 2743.2m	MVCD meters Over 2743.2m up to 3048m	MVCD meters Over 3048m up to 3352.8m
765	800	2.49m	2.54m	2.62m	2.71m	2.80m	2.88m	2.97m	3.05m	3.14m	3.22m	3.31m	3.39m
500	550	1.57m	1.6m	1.66m	1.73m	1.79m	1.85m	1.91m	1.98m	2.04m	2.11m	2.17m	2.24m
345	362	0.97m	0.99m	1.03m	1.08m	1.12m	1.16m	1.21m	1.26m	1.30m	1.35m	1.40m	1.44m
287	302	1.18m	0.88m	1.26m	1.31m	1.36m	1.41m	1.46m	1.51m	1.57m	1.62m	1.68m	1.73m
230	242	0.92m	0.94m	0.98m	1.02m	1.06m	1.11m	1.15m	1.19m	1.24m	1.29m	1.33m	1.38m
161*	169	0.62m	0.64m	0.67m	0.69m	0.73m	0.76m	0.79m	0.82m	0.85m	0.89m	0.92m	0.96m
138*	145	0.53m	0.54m	0.57m	0.59m	0.62m	0.65m	0.67m	0.70m	0.73m	0.76m	0.79m	0.82m
115*	121	0.44m	0.45m	0.47m	0.49m	0.51m	0.53m	0.56m	0.58m	0.61m	0.63m	0.66m	0.69m
88*	100	0.36m	0.37m	0.38m	0.40m	0.42m	0.44m	0.46m	0.48m	0.50m	0.52m	0.54m	0.57m
69*	72	0.26m	0.26m	0.27m	0.29m	0.30m	0.31m	0.33m	0.34m	0.36m	0.37m	0.39m	0.41m

* Such lines are applicable to this standard only if PC has determined such per FAC-014 (refer to the Applicability Section above)

Table 1 (CONT) — Minimum Vegetation Clearance Distances (MVCD)[7]

For **Direct Current** Voltages feet (meters)

(DC) Nominal Pole to Ground Voltage (kV)	(DC) Nominal Pole to Ground Voltage (kV) Over sea level up to 500 ft (Over sea level up to 152.4 m)	(DC) Nominal Pole to Ground Voltage (kV) Over 500 ft up to 1000 ft (Over 152.4 m up to 304.8 m	(DC) Nominal Pole to Ground Voltage (kV) Over 1000 ft up to 2000 ft (Over 304.8 m up to 609.6m)	(DC) Nominal Pole to Ground Voltage (kV) Over 2000 ft up to 3000 ft (Over 609.6m up to 914.4m	(DC) Nominal Pole to Ground Voltage (kV) Over 3000 ft up to 4000 ft (Over 914.4m up to 1219.2m	(DC) Nominal Pole to Ground Voltage (kV) Over 4000 ft up to 5000 ft (Over 1219.2m up to 1524m	(DC) Nominal Pole to Ground Voltage (kV) Over 5000 ft up to 6000 ft (Over 1524 m up to 1828.8 m)	(DC) Nominal Pole to Ground Voltage (kV) Over 6000 ft up to 7000 ft (Over 1828.8m up to 2133.6m)	(DC) Nominal Pole to Ground Voltage (kV) Over 7000 ft up to 8000 ft (Over 2133.6m up to 2438.4m)	(DC) Nominal Pole to Ground Voltage (kV) Over 8000 ft up to 9000 ft (Over 2438.4m up to 2743.2m)	(DC) Nominal Pole to Ground Voltage (kV) Over 9000 ft up to 10000 ft (Over 2743.2m up to 3048m)	(DC) Nominal Pole to Ground Voltage (kV) Over 10000 ft up to 11000 ft (Over 3048m up to 3352.8m)
±750	14.12ft (4.30m)	14.31ft (4.36m)	14.70ft (4.48m)	15.07ft (4.59m)	15.45ft (4.71m)	15.82ft (4.82m)	16.2ft (4.94m)	16.55ft (5.04m)	16.91ft (5.15m)	17.27ft (5.26m)	17.62ft (5.37m)	17.97ft (5.48m)
±600	10.23ft (3.12m)	10.39ft (3.17m)	10.74ft (3.26m)	11.04ft (3.36m)	11.35ft (3.46m)	11.66ft (3.55m)	11.98ft (3.65m)	12.3ft (3.75m)	12.62ft (3.85m)	12.92ft (3.94m)	13.24ft (4.04m)	13.54ft (4.13m)
±500	8.03ft (2.45m)	8.16ft (2.49m)	8.44ft (2.57m)	8.71ft (2.65m)	8.99ft (2.74m)	9.25ft (2.82m)	9.55ft (2.91m)	9.82ft (2.99m)	10.1ft (3.08m)	10.38ft (3.16m)	10.65ft (3.25m)	10.92ft (3.33m)
±400	6.07ft (1.85m)	6.18ft (1.88m)	6.41ft (1.95m)	6.63ft (2.02m)	6.86ft (2.09m)	7.09ft (2.16m)	7.33ft (2.23m)	7.56ft (2.30m)	7.80ft (2.38m)	8.03ft (2.45m)	8.27ft (2.52m)	8.51ft (2.59m)
±250	3.50ft (1.07m)	3.57ft (1.09m)	3.72ft (1.13m)	3.87ft (1.18m)	4.02ft (1.23m)	4.18ft (1.27m)	4.34ft (1.32m)	4.5ft (1.37m)	4.66ft (1.42m)	4.83ft (1.47m)	5.00ft (1.52m)	5.17ft (1.58m)

List of Acronyms and Abbreviations

ANSI	American National Standards Institute
IEEE	Institute of Electrical and Electronics Engineers
IVM	Integrated Vegetation Management
NERC	North American Electric Reliability Corporation

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